

**PUBLIC UTILITIES COMMISSION**

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December 28, 2017

Agenda ID #16225  
Quasi-legislative**TO PARTIES OF RECORD IN RULEMAKING 16-02-007:**

This is the proposed decision of Commissioner Liane M. Randolph. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's February 8, 2018 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ ANNE E. SIMON

Anne E. Simon

Acting Chief Administrative Law Judge

AES:lil

Attachment

**PROPOSED DECISION**

Agenda ID #16225  
Quasi-Legislative

Decision **PROPOSED DECISION OF COMMISSIONER RANDOLPH**  
**(Mailed 12/28/2017)**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Develop an  
Electricity Integrated Resource Planning  
Framework and to Coordinate and Refine  
Long-Term Procurement Planning  
Requirements.

Rulemaking 16-02-007  
(Filed February 11, 2016)

**DECISION SETTING REQUIREMENTS FOR LOAD SERVING ENTITIES  
FILING INTEGRATED RESOURCE PLANS**

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Attachment A: Standard Integrated Resource Plan Template

Attachment B: Guide to Production Cost Modeling in the IRP Proceeding

## **DECISION SETTING REQUIREMENTS FOR LOAD SERVING ENTITIES FILING INTEGRATED RESOURCE PLANS**

### **Summary**

The purpose of this decision is to set requirements for all load-serving entities (LSEs) under the jurisdiction of the Commission to file Integrated Resource Plans (IRPs) on or before June 1, 2018. This decision represents the Commission's implementation of Public Utilities Code Sections 454.51 and 454.52, enacted as part of Senate Bill (SB) 350 (2015, DeLeón), as well as modifications to those sections added by SB 338 (2016, Skinner) and Assembly Bill (AB) 759 (2017, Dahle).

This decision adopts a two-year planning cycle for the Commission to conduct modeling and analysis, set greenhouse gas (GHG) emissions targets, and consider IRP filings from all LSEs. The filings by each LSE will be required to include at least one scenario that conforms to the Commission's planning direction, while also presenting any LSE-preferred scenarios that may deviate from the Commission's planning standards with appropriate justification.

The IRPs will be the vehicle for LSEs proposing actual procurement of additional resources to meet the planning requirements adopted herein. At the end of each two-year cycle, the Commission will authorize procurement, where appropriate, that is necessary to occur within the next 1-3 years, to meet the targets and needs identified in the IRP process. The first such procurement authorization, if needed, is anticipated to come near the end of 2018 at the end of the first IRP cycle. All LSE IRPs will be required to describe how they meet certain requirements related to disadvantaged communities.

This decision also describes the GHG emissions planning target the Commission recommends to the California Air Resources Board (CARB) for assignment to the electricity sector as a whole, which is set by this decision at 42 million metric tons

(MMT) by 2030.<sup>1</sup> The optimal electricity resource portfolio associated with this electric sector GHG target is also described and adopted herein. This optimal portfolio was developed by Commission staff conducting modeling using the RESOLVE model to prioritize meeting the GHG reduction targets at least cost, while also maintaining reliability.

The portfolio associated with the Default Scenario modeled by Commission staff will be forwarded to the California Independent System Operator for use in its Transmission Planning Process (TPP) as the reliability base case, while the 42 MMT Scenario portfolio will be the basis for the policy-driven scenario recommended by the Commission in the TPP.

We do not require in this decision any early renewable procurement activities designed to capture the federal tax credits that are declining over the next few years, and instead opt for a steady approach to ongoing procurement of GHG-beneficial resources over the planning horizon to 2030.

Individual LSE-specific GHG benchmarks are calculated and required for use in IRP development. In addition, this decision adopts a GHG Planning Price of \$150 per metric ton of carbon dioxide equivalent in 2030<sup>2</sup> and directs its utilization as part of individual LSE IRP development, as well as its potential use as a GHG Adder in evaluating the cost-effectiveness of distributed energy resources.

Finally, this decision lays out additional planning activities that will be undertaken by the Commission, and its staff and consultants, in this rulemaking in 2018, prior to the commencement of the next IRP cycle and in parallel with consideration of the individual LSE IRPs. Those activities include additional production cost modeling and analysis to calibrate models to evaluate the aggregated LSE IRPs leading to a Preferred System Plan,

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<sup>1</sup> This planning target is comparable to 46 MMT utilizing the GHG accounting methodology from CARB to develop its Scoping Plan Update, due mainly to differences in accounting for emissions from on-site combined heat and power.

<sup>2</sup> The dollars-per-metric ton figures in this decision all represent 2016 real dollars unless otherwise noted.

development of a common resource valuation methodology, and additional analysis of possible impacts on the natural gas fleet availability and need.

This proceeding remains open.

## **1. Procedural Background**

This proceeding began with a great deal of informal work by Commission staff and parties. Commission staff circulated informal staff working papers, conducted webinars and workshops, and sought informal party comments over most of 2016 and the first half of 2017.

Following is a list of informal activities that were conducted by Commission staff during the early stages of this proceeding.

### Opening Workshop

- June 24, 2016: Workshop held on general concept of integrated resource planning, with guest presentations from other jurisdictions, including from a Washington State Commissioner, PacifiCorp, and the Regulatory Assistance Project; as well as a general overview of the PATHWAYS model analysis conducted for California Air Resources Board (CARB) by consultants Energy and Environmental Economics.

### Original Staff Concept Paper

- August 11, 2016: Staff Concept Paper circulated for informal comment
- August 24, 2016: Webinar conducted on staff concept paper
- August 31, 2016: Parties provided pre-workshop informal comments
- September 26, 2016: Workshop conducted

### Analytical Framework

- September 30, 2016: Staff Analytical Framework discussed at September 26, 2016 workshop circulated for informal comment
- October 14, 2016: Parties provided informal comments

### Scenario Development

- October 24, 2016: Staff Proposed Approach to Scenario Development circulated for informal comment



- October 27, 2016 and November 10, 2016: Webinars conducted to discuss scenario development
- November 3, 2016: Parties provided informal comments
- December 16, 2016: Half-day workshop conducted
- December 27, 2016: Staff issued questions related to the December 16 workshop discussions
- January 13, 2017: Parties provided informal comments

#### Modeling Advisory Group

- October 5, 2016: Staff circulated draft charter for the Modeling Advisory Group for informal comment
- October 14, 2016: Parties provided informal comments
- October 20, 2016, November 3, 2016, November 17, 2016 and January 12, 2017: Webinars conducted
- December 16, 2016: Half-day workshop conducted

#### Load serving entity (LSE)-specific greenhouse gas (GHG) emissions targets

- November 15, 2016: Staff white paper on implementing GHG planning targets for Integrated Resource Planning (IRP) circulated
- November 30, 2016: Parties provided informal comments
- December 7, 2016: Parties provided informal reply comments

#### Electric Sector GHG targets

- February 10, 2017: California Public Utilities Commission (CPUC or Commission) and California Energy Commission (CEC) Joint Staff Paper: Options for Setting GHG Planning Targets for Integrated Resource Planning and Apportioning Targets among Publicly Owned Utilities and Load Serving Entities, circulated for informal comment
- February 21, 2017: Parties provided pre-workshop informal comments
- February 23, 2017: Joint CEC/CPUC workshop on setting GHG targets conducted
- March 9, 2017: Parties provided informal reply comments

In addition to the above informal activities, on December 21, 2016 a ruling by the assigned Commissioner and Administrative Law Judge (ALJ) was issued which sought

comment on other aspects of the IRP process, including the appropriate treatment of disadvantaged communities in the IRP process, among other items.

On February 17, 2017, the following 23 parties filed comments on the December 21, 2016 ruling: Alliance for Retail Energy Markets (AReM); American Wind Energy Association California Caucus (AWEA); Anza Electric Cooperative, Plumas-Sierra Rural Electric Cooperative, and Surprise Valley Electrification Corp. (jointly: Cooperatives); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA), Sierra Club, and the Greenlining Institute (Greenlining) (jointly); California Municipal Utilities Association (CMUA); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); City of Lancaster, Silicon Valley Clean Energy Authority, Marin Clean Energy (MCE), and Sonoma Clean Power Authority (jointly, CCA Parties); County of Los Angeles on behalf of the Southern California Regional Energy Network (LA County on behalf of SoCalREN); Environmental Defense Fund (EDF); GRID Alternatives (GRID); Imperial County;<sup>3</sup> Independent Energy Producers (IEP); the Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); PacifiCorp; Protect Our Communities Foundation (POC); San Diego Gas & Electric Company (SDG&E); Solar Energy Industries Association (SEIA); Southern California Edison Company (SCE); Union of Concerned Scientists (UCS); and Utility Consumers' Action Network (UCAN).

The following 12 parties filed reply comments on February 27, 2017 in response to the December 21, 2016 ruling: California Wind Energy Association (CalWEA); Calpine; CEJA and Sierra Club (jointly); EDF; Imperial County; IEP; ORA; PG&E; SCE; UCS; UCAN; and Vote Solar.

Following the above-mentioned informal proceeding activity conducted by Commission staff, on May 16, 2017, an ALJ ruling was issued seeking comment on a

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<sup>3</sup> Imperial County's comments were filed on February 16, 2017.

Commission Staff Proposal titled “Proposal for Implementing Integrated Resource Planning at the CPUC: An Energy Division Staff Proposal” (Staff Proposal).

On May 24, 2017, Commission staff held a public webinar to allow parties to ask clarifying questions about the IRP Staff Proposal.

The following 56 parties filed timely comments in response to the May 16, 2017 ALJ ruling and Staff Proposal: Advanced Energy Economy (AEE); AReM; AWEA; Anza, Plumas-Sierra, and Surprise Valley Electric Cooperatives (Coops); Association of California Water Agencies; Bay Area Municipal Transmission Group (BAMx); Brookfield Renewable (Brookfield); California Community Choice Association (CalCCA); California Biomass Energy Alliance (CBEA); CESA; CEJA and Sierra Club, jointly; California Hydrogen Business Council (CHBC); California Independent System Operator (CAISO); California Large Energy Consumers Association (CLECA); California Unions for Reliable Energy (CURE); CalWEA; Calpine; CEERT; Citizens Energy Corporation (Citizens); Clean Coalition; Defenders of Wildlife (Defenders); Eagle Crest Energy; EDF; Friends of the Earth; Green Power Institute (GPI); GRID; GridLiance West Transco LLC (GridLiance West); Imperial County; Institute for Policy Integrity; L. Jan Reid (Reid); Large Scale Solar Association (LSA); Liberty Utilities (CalPeco Electric); Magellan Wind LLC (Magellan); National Grid; Natural Resources Defense Council (NRDC); NRG Energy, Inc. (NRG); Office of Ratepayer Advocates (ORA); PG&E; PacifiCorp; Pathfinder CAES 1, LLC (Pathfinder); Pattern Energy Group 2 LP (Pattern); POC; San Diego County Water Authority (Water Authority); SDG&E; Shell Energy North America (Shell); SCE; SEIA; Southwestern Power Group II, LLC (SWPG); TransCanyon, LLC (TransCanyon); TransWest Express LLC (TransWest); The Utility Reform Network (TURN); UCS; UCAN; Valley Electric Association, Inc. (VEA); Vote Solar; and Western Power Trading Forum (WPTF).

The following 37 parties filed timely reply comments in response to the May 16, 2017 ALJ ruling and Staff Proposal comments of other parties: AEE; AReM; BAMx; CAISO; CalCCA; Calpine; CalPeco; CalWEA; CEERT; CEJA and Sierra Club, jointly;

CESA; Clean Coalition; Coops; CURE; Defenders of Wildlife; Eagle Crest; EDF; GPI; GridLiance West; Imperial County; IEP; LSA; MCE; and Peninsula Clean Energy, jointly; NRDC; NRG; ORA; PacifiCorp; Pathfinder; PG&E; SCE; SDG&E; SWPG; TransCanyon; TURN; VEA; Vote Solar; and WPTF.

On July 19, 2017, Commission staff released a preliminary version of the modeling results. A full-day workshop for discussion with parties was held on July 27, 2017. These were informal steps designed to advance understanding and discussion among the parties in advance of the opportunity to submit formal comments on the modeling results and recommendations.

On September 19, 2017, an ALJ ruling was issued formally incorporating the modeling results into the record of the proceeding via attachments to the ruling, and seeking comment on a series of questions embedded in the ruling. This September 19, 2017 ALJ ruling represented the staff recommendation for the Reference System Plan (RSP), proposed to be adopted by the Commission. A two-day workshop to discuss this ruling was held on September 25-26, 2017.

Although the July 19, 2017 preliminary modeling results did not take into account parties' comments filed on the May 16, 2017 IRP staff proposal, the September 19, 2017 version of the modeling results did include staff's consideration of those comments. This decision discusses those party comments on the May IRP Staff Proposal as well.

In response to the September 19, 2017 ALJ ruling on the proposed RSP, the following 53 parties filed comments on October 26, 2017: AEE; AReM; AWEA; BAMx and the City and County of San Francisco (CCSF), jointly; CBEA; CalCCA; California Efficiency and Demand Management Council (CEDMC); CESA; CAISO; CLECA; CMUA; CURE; CalWEA; Calpine; CEJA and Sierra Club, jointly; CEERT; Cogeneration Association of California (CAC); Defenders; Eagle Crest; EDF; GPI; GridLiance West; Imperial County; Imperial Irrigation District (IID); IEP; Reid; LSA; LS Power; Nation Grid; NRDC; NRG; ORA; Ormat Technologies, Inc. (Ormat); PG&E; Pattern Energy (Pattern); POC; Range Energy Storage Systems, LLC (Range); SDG&E;

Silicon Valley Leadership Group (SVLG); SEIA; SCE; Southern California Gas Company (SoCalGas); SWPG; Tesla; The Nature Conservancy (TNC); TURN; TransCanyon; TransWest; Trident Winds, LLC (Trident); UCS; UCAN; VEA; and Vote Solar.

An all-party meeting with all five Commissioners present was held on November 2, 2017. Commission staff made brief presentations on topics related to the proposed RSP, with opportunities for Commissioners and parties to comment throughout the day.

The following 36 parties filed reply comments on the proposed RSP on November 9, 2017: AEE; AReM; AWEA; BAMx and CCSF, jointly; CAC; CAISO; CalCCA; Calpine; CalWEA; CEERT; CEJA, EDF, NRDC, Sierra Club, and UCS, jointly; CESA; CLECA; CMUA; Defenders; Diamond Generating Corporation (Diamond); Eagle Crest; EDF; GPI; GridLiance; IEP; Imperial County; IID; Reid; LSA; ORA; Ormat; PG&E; POC; Range; SCE; SDG&E; Shell; TransCanyon; TransWest; and TURN.

## **2. Overall Integrated Resource Planning Process**

The two Public Utilities Code sections<sup>4</sup> that established the Commission's need to create an IRP process are reproduced below. These two sections govern all of our activities in this proceeding.

### **454.51.**

The commission shall do all of the following:

- (a) Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner. The portfolio shall rely upon zero carbon-emitting resources to the maximum extent reasonable and be designed to achieve any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of

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<sup>4</sup> All references hereafter are to the Public Utilities Code unless otherwise specified.

2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation.

- (b) Direct each electrical corporation to include, as part of its proposed procurement plan, a strategy for procuring best-fit and least-cost resources to satisfy the portfolio needs identified by the commission pursuant to subdivision (a).
- (c) Ensure that the net costs of any incremental renewable energy integration resources procured by an electrical corporation to satisfy the need identified in subdivision (a) are allocated on a fully nonbypassable basis consistent with the treatment of costs identified in paragraph (2) of subdivision (c) of Section 365.1.
- (d) Permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration need identified in subdivision (a). If the commission finds this need is best met through long-term procurement commitments for resources, community choice aggregators shall also be required to make long-term commitments for resources. The commission shall approve proposals pursuant to this subdivision if it finds all of the following:
  - (1) The resources proposed by a community choice aggregator will provide equivalent integration of renewable energy.
  - (2) The resources proposed by a community choice aggregator will promote the efficient achievement of state energy policy objectives, including reductions in greenhouse gas emissions.
  - (3) Bundled customers of an electrical corporation will be indifferent from the approval of the community choice aggregator proposals.
- (e) All costs resulting from nonperformance will be borne by the electrical corporation or community choice aggregator responsible for them.

**454.52.**

- (a) (1) Commencing in 2017, and to be updated regularly thereafter, the commission shall adopt a process for each load-serving entity, as defined in Section 380, to file an integrated resource plan, and a schedule for periodic updates to the plan, to ensure that load-serving entities do the following:
  - (A) Meet the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each load-serving entity that reflect the electricity sector's percentage in

achieving the economywide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

- (B) Procure at least 50 percent eligible renewable energy resources by December 31, 2030, consistent with Article 16 (commencing with Section 399.11) of Chapter 2.3.
  - (C) Enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.
  - (D) Minimize impacts on ratepayers' bills.
  - (E) Ensure system and local reliability.
  - (F) Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.
  - (G) Enhance distribution systems and demand-side energy management.
  - (H) Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.
- (2) (A) The commission may authorize all source procurement for electrical corporations that includes various resource types including demand-side resources, supply side resources, and resources that may be either demand-side resources or supply side resources, taking into account the differing electrical corporations' geographic service areas, to ensure that each load-serving entity meets the goals set forth in paragraph (1).
  - (B) The commission may approve procurement of resource types that will reduce overall greenhouse gas emissions from the electricity sector and meet the other goals specified in paragraph (1), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan.
- (b) (1) Each load-serving entity shall prepare and file an integrated resource plan consistent with paragraph (2) of subdivision (a) on a time schedule directed by the commission and subject to commission review.
- (2) Each electrical corporation's plan shall follow the provisions of Section 454.5.
- (3) The plan of a community choice aggregator shall be submitted to its governing board for approval and provided to the commission for

certification, consistent with paragraph (5) of subdivision (a) of Section 366.2, and shall achieve the following:

- (A) Economic, reliability, environmental, security, and other benefits and performance characteristics that are consistent with the goals set forth in paragraph (1) of subdivision (a).
- (B) A diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.
- (C) The resource adequacy requirements established pursuant to Section 380.
- (4) The plan of an electric service provider shall achieve the goals set forth in paragraph (1) of subdivision (a) through a diversified portfolio consisting of both short-term and long-term electricity, electricity-related, and demand reduction products.
- (c) To the extent that additional procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5, the commission shall ensure that the costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is no cost-shifting among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51.
- (d) In order to eliminate redundancy and increase efficiency, the process adopted pursuant to subdivision (a) shall incorporate, and not duplicate, any other planning processes of the commission.
- (e) This section applies to an electrical cooperative, as defined in Section 2776, only if the electrical cooperative has an annual electrical demand exceeding 700 gigawatt hours (GWh), as determined on a three-year average commencing with January 1, 2013.

## **2.1. Staff Proposal**

The May 2017 IRP Staff Proposal included a proposed iterative IRP process at the Commission that would repeat every two years, similar to the cycle conducted when the planning process was called long-term procurement planning (LTPP). Unlike the previous LTPP process, which applied to the investor-owned utilities (IOUs) only, the IRP process incorporates all LSEs which operate within the service territories and whose



customers utilize transmission and distribution services of the IOUs. The process was proposed to achieve the state's policy goals by balancing a system-wide perspective with a consideration of the unique circumstances of each individual LSE.

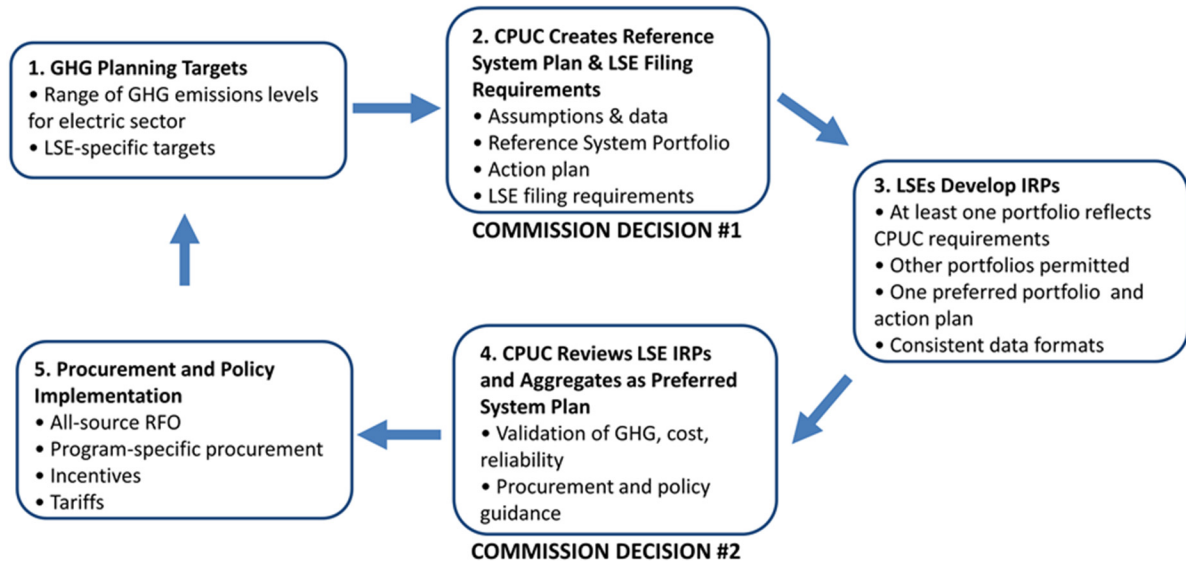
The basic steps of the iterative, biennial IRP process are summarized as follows:

- The Commission will lead the effort to represent the electricity system-wide perspective by identifying a portfolio of new resources that together meet policy goals, proposed as the RSP. In this step, Commission staff will conduct modeling to identify an optimal combination of resources (i.e., the reference system portfolio) to meet the electricity sector's portion of responsibility for meeting the 2030 California GHG emissions goal established by CARB while achieving the state's other policy goals, and identify recommended Commission policy actions.
- Individual LSEs will then use the Commission-adopted RSP as a guide to generating their own preferred portfolios.
- LSE portfolios will be submitted to the Commission in individual IRP filings, where they will be aggregated into a new system-wide portfolio and evaluated for compliance with policy goals.
- The new, aggregated portfolio and associated policy actions will be adopted by the Commission as the Preferred System Plan (PSP) and will drive procurement and program activity across multiple supply and demand resources.
- The IRP process will repeat every two years.

Further, staff proposed that the 2017-18 cycle of the proposed IRP process be designed to demonstrate the feasibility of the proposed process, while still relying on separate resource-specific proceedings for planning and implementation for their particular areas. In future cycles, the hope was that IRP would absorb the planning function across resource areas while individual proceedings continue to be responsible for implementation and procurement functions.

Figure 1 below summarizes the proposal.

**Figure 1. Proposed IRP Process.**



## 2.2. Comments of Parties

Numerous comments on the overall process were submitted by the LSEs, or their representatives, in their June 28, 2017 comments. PG&E argued that the IRP process should be designed to produce information to help LSEs make procurement decisions, but should not make those decisions for the LSEs. In particular, PG&E was concerned that the IRP process not supplant Section 454.5, which established criteria for the Commission's review and approval of procurement decisions, including cost recovery, as well as for ensuring reliability and LSE compliance with Commission directives.

PG&E also commented that the first IRP should not be overly ambitious, but instead lay a foundation to establish a clear and robust process for future IRPs. PG&E characterized the IRP process as for planning purposes only, and not a procurement proceeding. PG&E's opinion is that transitioning away from the pre-existing resource planning paradigm is complex and cannot be completed in only one cycle.

Instead, PG&E emphasized making the first IRP cycle informational and for proof-of-concept purposes, completely removing any procurement authorization possibility, unless specific reliability risks are identified.

SCE similarly commented that this cycle of the IRP should not be used to direct procurement or investment decisions absent a near-term reliability need. After this cycle, SCE would prefer that the IRP cycle be four years instead of two, to allow for the significant analysis required and lesson learned from previous cycles.

SDG&E was concerned that the LSEs be heavily involved in the analysis and modeling to support the IRP process, including the RSP and PSP. SDG&E recommended an informal working group process, which is essentially what has already been occurring. SDG&E also made process comments, indicating the need for formal comments related to Steps 1 and 2 in Figure 1, testimony and evidentiary hearings for Step 3, and more formal comments for Steps 4 and 5.

SDG&E also agreed with SCE and PG&E that no procurement should be authorized during the first cycle, unless it involves modification of existing procurement mandates, if warranted for reliability purposes.

Shell did not comment on the modeling process, but focused on the need to allow LSEs flexibility to develop their own portfolios to meet the needs of their customers, which achieving the emissions reductions required. Shell also objected to the idea that the Commission would “approve” any electric service providers (ESP) plans.

WPTF generally supported demonstrating the feasibility of the proposed process, but did not like the characterization that the Commission would “approve” of individual LSE plans, instead focusing on the Commission’s role setting goals, monitoring performance, and ensuring compliance with specific mandated requirements in statute.

VEA supported the overall process outlined, and strongly supported the notion that the IRPs should inform transmission planning in particular.

Consumer groups generally also supported the outline of the process suggested by Commission staff. ORA particularly supported the emphasis on meeting GHG targets at

least cost, and argued that LSEs should have flexibility to procure least-cost resources that provide the greatest value to ratepayers.

TURN cautioned against too much emphasis in the IRP process on “short-term” needs, suggesting that those considerations belong in the resource adequacy dockets. They were also concerned about any Commission findings of the need for large capital investments, and the potential cost allocation issues associated with such decisions.

UCAN supported the general approach, with special emphasis on the proposed PSP and associated short-term activities. UCAN emphasized the importance of establishing the groundwork and structure for IRP and moving through the entire process once in 2017-18.

CLECA had questions about the overall process and particularly the composite analysis of all LSE plans, but supported 2017-18 being a trial run through the process.

CAISO had specific comments about the IRP process, because of its importance for process alignment with the CEC’s Integrated Energy Policy Report (IEPR) and the CAISO Transmission Planning Process (TPP). The CAISO was also concerned that a two-year cycle may not be long enough to ensure thorough vetting of assumptions and outputs, along with robust stakeholder engagement and review.

Numerous generators and their representatives also commented on the suggested process. AWEA noted the tension between flexibility and comprehensiveness and focused on the need to ensure near-term decisions to move to procurement as soon as possible, in particular to take advantage of expiring federal tax credits.

Brookfield supported the intent of the 2017-18 cycle to test feasibility, but urged authorization of procurement if analysis warranted.

Calpine generally supported the proposed process, but stated concerns about cross-sectoral impacts. NRG also supported the process in general.

CalWEA thought the proposed process fell short on consistency between the RSP and the individual LSE Plans. They supported the concept of creating separate tracks, if

needed, to address collective investments needed in large assets, such as bulk storage or major transmission upgrades.

CEERT expressed concerns about how long the proposed process would take and criticized too much emphasis on renewable integration to the exclusion of other issues addressed in Senate Bill (SB) 350 as a whole. CEERT also felt that the additional modeling and sensitivity analysis was excessive, and that the Commission should instead focus on guiding procurement.

CESA generally supported the structure, and focused comments on how to quantify compliance of individual LSE plans, perhaps within certain ranges in each cycle. They also suggested benchmarking the RESOLVE model with other industry-accepted and tested grid planning models.

Clean Coalition wanted more detail on how the individual LSE Plans will be evaluated against the RSP.

GPI generally supported treating 2017-18 as a trial run before basing procurement decisions on the IRP analysis done thus far. They also were concerned about how to move from the RSP, to the individual LSE plans and then forming the PSP, with the need for possible adjustments to individual LSE plans.

LSA also supported the overall process, but stated several concerns about the schedule, the potential for varying levels of detail and rigor at various steps in the process (too much or too little), and the degree of autonomy afforded to individual LSEs.

Pathfinder supported the general process but recommended incorporating additional feedback steps between the RSP and the PSP. They would also prefer more specificity about the LSE Plan evaluation process.

Vote Solar recommended that the IRP analysis be done at a more granular level of detail to analyze distributed energy resources (DERs) to be optimized. They felt that the modeling would not accurately represent the CAISO market dynamics nor account for the flexible capacity needs accurately. Their main concern was the lack of analytical grounding in grid reliability terms.

Numerous environmental groups also filed comments on the proposed IRP process. CEJA and Sierra Club generally supported the staff's proposed process, including the proposal for an RSP and a PSP. They also recommended additional steps to ensure LSE compliance with all requirements, monitoring and reporting of GHG emissions, air pollution emissions, and disadvantaged communities impacts, and additional opportunities for public participation, particularly at the local level.

EDF focused its comments on the need for more granular planning information on DERs.

NRDC was concerned about the need for more of a compliance framework for evaluating the individual plans.

POC was concerned that individual LSEs have too much flexibility under the staff proposed approach, thereby potentially rendering the entire IRP process a meaningless exercise.

### **2.3. Discussion**

We agree with the outline of the staff recommendation to institute a two-year IRP cycle similar to our conduct of past LTPP proceedings. Hereafter, the process described in Figure 1 above will begin in each odd-numbered calendar year, culminating in the approval and potential procurement authorization at the end of each even-numbered year.

During odd-numbered years (2019, 2021, 2023, 2025, 2027, and 2029), the following activities will take place:

- Commission staff will conduct modeling and analysis to recommend a GHG emissions target for the electricity sector, identify the optimal portfolio of resources to meet the target, and calculate a GHG Planning Price for use in IRP planning and demand-side resource cost-effectiveness evaluation.
- No later than December 31, the Commission will adopt an RSP consisting of the items above, for use in individual LSE IRP development and the CAISO's TPP commencing in February of the even-numbered years.

During even-numbered years (2018, 2020, 2022, 2024, 2026, and 2028), the following activities will take place:

- By May 1 (except 2018, where the deadline will be June 1), LSEs will file IRPs to be considered by the Commission.
- Commission staff and/or its consultants will conduct production cost modeling (PCM) to aggregate individual LSE plans and conduct a reliability assessment to recommend a PSP.
- By December 31, the Commission will adopt a PSP for use in the CAISO TPP commencing in February of the odd-numbered years.
- By December 31, the Commission will approve and/or modify individual LSE Plans and authorize any associated procurement activity, as necessary, to commence in the following year.

### **3. Applicability of IRP requirements to all LSEs**

In this section we address the Commission's general authority to require IRPs from all LSEs, with certain contents, to be submitted for consideration.

#### **3.1. Staff Proposal**

In the May 2017 IRP Staff Proposal and in the RSP, Commission staff made the assumption that the Commission could require all LSEs, including IOUs, community choice aggregators (CCAs), ESPs and electric cooperatives (coops), regardless of other aspects of the Commission's regulatory authority, to submit IRPs for the Commission's consideration, with certain required contents. The IRP Staff Proposal differentiated among different LSE types for certain purposes, but assumed that the authority to require plans was universal, without presenting any specific legal analysis.

#### **3.2. Comments of Parties**

From the beginning of this proceeding, including in comments on the OIR, the coops presented arguments about the burden of participating in this complex planning process for small entities.

ESPs, whose collective interests are represented by AReM, and to some extent WPTF, as well as by individual ESP filings by Shell Energy and Calpine, among others, have generally not objected to the Commission's authority to require IRP submissions or

to review them. They have, however, objected to the idea that the Commission has the authority to approve or modify their submissions, due to the Commission's lack of authority over their contracts, rates, or terms and conditions of service. They have also suggested differential and generally less complex processes for ESPs, as distinct from IOUs or CCAs. For example, the ESPs and their representatives, in comments, regularly argued that the Commission does not have authority over ESP rates or terms and conditions of electric service to their customers, and therefore cannot require certain elements in the IRPs or processes associated with the submissions.

CCA representatives, by contrast, have argued that only each CCA program's local governing board has any authority over the planning and procurement decisions of CCAs. They argued that because the statute uses the term "certify" to describe the Commission's required action on individual CCA IRPs, the Commission's role is limited to "informal review of a CCA plan to ensure that it includes the content required by statute without assessing the substantive adequacy of said content."<sup>5</sup>

CalCCA also objected to the idea that CCAs would be required to file or submit their IRPs to the Commission for certification, arguing that because the statute states that the CCA plans must be "provided" to the Commission for "certification" that this can only mean informal provision and not any sort of formal filing as suggested by Commission staff.<sup>6</sup>

Next, CalCCA argued that while the IOUs are required to strictly comply with the eight criteria set forth in Section 454.52(a)(1) (A)-(H), the CCAs' IRPs are only required to achieve "benefits and performance characteristics" that are "consistent with" the eight criteria. Finally, CalCCA argued that while the Commission is generally responsible for ensuring that LSE IRPs comply with the eight criteria, Section 454.52(b)(3) carves out a

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<sup>5</sup> CalCCA October 26, 2017 Comments on the Proposed RSP, at 6.

<sup>6</sup> CalCCA June 28, 2017 Comments on the Energy Division Staff Proposal, at A-3.



specific exception to this for CCA IRPs by explicitly vesting each CCA program's governing board with the authority to approve that program's IRP.

CalCCA repeatedly argued that CCAs are public agencies established to provide local control and oversight of procurement and other energy matters, and they are responsible to the voters they serve, thereby making it unnecessary for the Commission to exercise any substantive oversight over their IRPs. CalCCA painted a picture of CCAs whose purpose is to exceed clean energy mandates and make clean energy a centerpiece of CCA programs.<sup>7</sup> Their comments cited to the aggressive pursuit of clean energy by MCE and other operational CCAs.

In sum, the major feature of the CCA arguments is that the Commission's authority amounts to only a rubber stamp of any IRP contents authorized by a CCA governing board, whose authority is primary over the Commission's when it comes to the substance of the plans.

The IOUs all filed comments objecting to the CalCCA and other CCA parties' interpretations of SB 350, pointing out the failure of the CCAs to make a distinction between planning activities, which are the subject of this decision, and procurement activities, which may come about as a result of these planning activities.

### **3.3. Discussion**

In July 2017, the Legislature passed Assembly Bill (AB) 759 (Dahle, 2017) that created an exemption from the requirements of Section 454.52 for small electric cooperatives, adding section 454.52(e), which states:

(e) This section applies to an electrical cooperative, as defined in Section 2776, only if the electrical cooperative has an annual electrical demand exceeding 700 GWh, as determined on a three-year average commencing with January 1, 2013.

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<sup>7</sup> CalCCA October 26, 2017 Comments on the Proposed RSP, at 2-3.

Thus, coops whose energy sales do not exceed the three-year average of 700 Gwh are exempted from the requirements to submit an IRP to the Commission. Coops meeting this criterion will be required to submit information substantiating their eligibility for this exemption at the same time other LSEs are required to submit their IRPs, as detailed in Section 2 of this decision.

The other major authority and applicability issue argued in comments is related to the Commission's role with respect to CCA IRPs. We maintain that our authority and responsibility over CCA planning is considerably broader than the CCAs and their representatives argue.

The CCAs and their representatives focus chiefly on Section 454.52(b)(3) which states, in part: "The plan of a community choice aggregator shall be submitted to its governing board for approval and provided to the commission for certification..." The CCAs argue this somehow gives the Commission lesser authority over CCA IRPs than any other LSE IRP. We disagree. The purpose of the reference to the CCA governing board is to recognize that it has a role in the context of CCA plans that does not exist for other LSEs such as IOUs and ESPs. This language does not somehow subjugate the Commission's authority to that of the CCA governing boards. Instead, it simply recognizes that CCAs will have an additional step in their planning process, to seek approval of their governing boards prior to submission of their plans to the Commission.

In addition, the Commission's role is to certify substantive compliance of the CCA's plan as "consistent with" all of the following requirements of Section 454.52(b)(3):

(A) Economic, reliability, environmental, security, and other benefits and characteristics that are consistent with the goals set forth in paragraph (1) of subdivision (a).<sup>8</sup>

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<sup>8</sup> These consist of all of the requirements of Section 454.52(a) (1)(A)-(H) including GHG emissions targets, RPS requirements, minimizing impacts on ratepayer bills, minimizing local air pollutants, enhancing distribution systems and demand-side energy management, etc.

(B) A diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.

(C) The resource adequacy requirements established pursuant to Section 380.

Further, under Section 454.51(d) and (e), the Commission must:

(d) Permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration need identified in subdivision (a). If the Commission finds this need is best met through long-term procurement commitments for resources, community choice aggregators shall also be required to make long-term commitments for resources. The commission shall approve proposals pursuant to this subdivision if it finds all of the following:

(1) The resources proposed by a community choice aggregator will provide equivalent integration of renewable energy.

(2) The resources proposed by a community choice aggregator will promote the efficient achievement of state energy policy objectives, including reductions in greenhouse gas emissions.

(3) Bundled customers of an electrical corporation will be indifferent from the approval of the community choice aggregator proposals.

(e) Ensure that all costs resulting from nonperformance to satisfy the need in subdivision (a) or (d), as applicable, shall be borne by the electrical corporation or community choice aggregator that failed to perform.

This authority extends even further than even the IOUs argue. The IOU comments sought to make a distinction between planning and procurement activities. We agree with this distinction, but note that the above statutory language gives the Commission considerable authority over some aspects of CCA procurement, not just planning.

Taken together, Sections 454.51 and 454.52 give the Commission the basic authority and requirements to identify the optimal portfolio of resources to meet the state's GHG emissions goals in the electricity sector, and to adopt a process to require each LSE to file IRP, as stated in Section 454.52(a)(1), to meet those state goals. The recognition in the statute of the unique role of the CCAs' governing boards does not in any way reduce the Commission's authority to review and approve the substance of the CCA plans.

Not only that, but the Commission, if it finds a CCA plan to be non-conforming or not meeting statutory or Commission requirements, has the authority to order long-term procurement commitments, and to assign costs of non-performance with the approved plans to meet the identified needs for renewable integration, as identified in the Commission's RSP described in this decision, in accordance with Section 454.51(a). As described further in this decision, our expectation is that the CCAs' plans for renewable integration required by Section 454.51(d) will be included in their IRP filings.

CCAs are already required to meet one-year resource adequacy requirements according to Section 380. The Commission further finds that it will expect LSE plans to demonstrate how they will collectively bridge from the current one-year-ahead resource adequacy framework through to the long-term planning horizon. If sufficient procurement contracting is not demonstrated for renewable integration or reliability by all LSEs, including CCAs, the Commission has the authority to order long-term procurement commitments.

Thus, it is well within the authority of the Commission to require IRP filings, in any manner it determines, and to review the substance of those filings for compliance with the requirements articulated by the Commission in this decision, which are within the requirements outlined in Sections 454.51 and 454.52. Further, Commission "certification" of CCA plans is a discretionary action. The Commission may decide not to certify a CCA plan and/or to require modification of it, while acknowledging that a CCA governing board must approve the plan before it comes back to the Commission for additional consideration.

The plain language of Section 454.52(b)(1) summarizes the process best, stating: "Each load-serving entity shall prepare and file an integrated resource plan consistent with paragraph (2) of subdivision (a) on a time schedule directed by the Commission and subject to commission review."

Further, with respect to the Commission's authority over ESP IRP filings, there is nothing in the statute that creates differential responsibility or exceptions for the

Commission with respect to the IRP filings of these types of LSEs. We acknowledge our lack of involvement in setting the rates or terms of service for ESPs, but Sections 454.51 and 454.52 still apply to all LSEs, and give the Commission responsibility for reviewing and approving the plans of all LSEs.

We do note that there are various subsections of Sections 454.51 and 454.52 that apply only to electrical corporations (IOUs) and our implementation and enforcement of those sections will only be applied to the IOU LSEs. Those include, but are not limited to, Section 454.51(b) and (c), Section 454.52(a)(1)(C), and Section 454.52(b)(2).

#### **4. Modeling Analysis**

In the May 2017 IRP Staff Proposal, Commission staff laid out a set of recommended scenarios to be modeled, along with assumptions, outputs, metrics, and sensitivities, as well as a proposal for how to evaluate the potential impacts on disadvantaged communities. Parties then commented on the staff proposal, staff conducted the analysis, and then parties commented again on the analysis and the results. All of these steps are summarized below.

##### **4.1. Preliminary Proposed Analysis**

In the IRP Staff Proposal, Commission staff proposed to model four major scenarios of GHG emissions levels in the electric sector in the state by 2030. The four scenarios were defined by their respective GHG emissions, beginning with a Default Scenario at 62 million metric tons (MMT), which was the upper end of CARB's identified Scoping Plan range for the electric sector as of the January 2017 draft, and ending with a scenario where the electric sector took on an extra-large share of the economy-wide emissions in the state by reducing GHG emissions to 30 MMT by 2030.

Staff also proposed to conduct a range of sensitivity cases to test the importance of individual variables on the results.

The assumptions and scenarios were proposed to be run through a capacity-expansion model called RESOLVE, where the need for new resources would be evaluated in a least-cost manner, while still meeting reliability requirements.

#### **4.2. Comments of Parties**

Numerous parties commented on the broad outline of the analysis proposed in the IRP Staff Proposal.

#### **4.3. Final Analysis Conducted**

Taking into account the initial round of formal comments from parties, as well as informal comments received in working groups and workshops, Commission staff set up the design of the modeling work to reflect the range of GHG emissions expected to come from the electricity sector in 2030 in the Draft 2017 Climate Change Scoping Plan Update available from the CARB in January 2017.<sup>9</sup> At the time, based on CARB's economy-wide analysis of GHG emissions associated with abatement activities already planned or underway, the electric sector statewide was expected to emit between 42 MMT and 62 MMT in 2030, under CARB's "Proposed Scenario."

While there were some differences between CARB's modeling approach utilizing the PATHWAYS model and the one undertaken by Commission staff for IRP purposes, in basic terms the top end of the CARB's range was similar to what would be expected from a 33% renewables portfolio standard (RPS) requirement and business-as-usual amounts of other clean resources including energy efficiency and storage, for example.<sup>10</sup>

The lower end of the range (42 MMT) represented full implementation of the RPS (at the 50% level) plus doubling of energy efficiency, as required by SB 350, in addition to reaching the Commission's storage requirements for LSEs, and the continued penetration of rooftop solar photovoltaics (PV) under the net energy metering (NEM) tariff. Generally speaking, there were some differences in the modeling treatment of excess procurement of RPS ahead of compliance targets (banked for use in future compliance periods) between the CARB modeling and RESOLVE modeling, the latter of

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<sup>9</sup> Draft available at: [https://www.arb.ca.gov/cc/scopingplan/2030sp\\_pp\\_final.pdf](https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf).

<sup>10</sup> Additional documentation of CARB's modeling approach is available at: [https://www.arb.ca.gov/cc/scopingplan/app\\_d\\_pathways.pdf](https://www.arb.ca.gov/cc/scopingplan/app_d_pathways.pdf).

which also involves a much more granular treatment of the electricity sector emissions overall.

To reflect the CARB Scoping Plan Proposed Scenario range, Commission staff originally proposed (in the May 16, 2017 IRP Staff Proposal) to model four scenarios of GHG emissions for the electric sector, including the high (62 MMT), middle (52 MMT), and low (42 MMT) end of the Scoping Plan electric sector GHG emissions range, plus an additional scenario constrained at 30 MMT of GHG emissions, specifically the level associated with CARB's Alternative 1 Scenario, to test what would be required to be delivered from the electric sector if, on an economy-wide basis, it was more cost-effective or feasible for additional GHG emissions reductions to come from the electric sector in 2030.<sup>11</sup>

Another difference between CARB and Commission assumptions that was discovered during the analysis was with respect to accounting for behind-the-meter (BTM) combined heat and power (CHP) facility emissions. CARB's methodology counts these emissions as part of the electric sector, while for Commission modeling purposes they were treated as industrial emissions. This results in an approximately 4 MMT difference in all scenarios, which should be kept in mind when comparing results.

Commission staff and consultants utilized the RESOLVE model, which is an electricity capacity expansion model, to begin to analyze these four levels of GHG emissions. The model starts by incorporating all existing (operating) and/or contracted electric sector supply resources (as of approximately October 2016), and then selecting the lowest cost additional resources from among a set of representative resources characterized by fuel, cost, and GHG emissions characteristics, among others, to meet the remaining load. Following is a list of the baseline resources reflected in the RESOLVE starting point, prior to optimization of any new resources.

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<sup>11</sup> See additional documentation in CARB's PATHWAYS output tool at: [https://www.arb.ca.gov/cc/scopingplan/pathways\\_main\\_outputs\\_final\\_17jan2017.xlsm](https://www.arb.ca.gov/cc/scopingplan/pathways_main_outputs_final_17jan2017.xlsm).

Demand-Side

- Energy Efficiency: CEC's 2016 IEPR Mid Additional Achievable Energy Efficiency (AAEE) + additional AB 802 Efficiency – related to code baseline and behavioral impacts. These assumptions equate to approximately a 1.5x gain in energy efficiency by 2030.
- Behind-the-meter (BTM) solar PV: CEC 2016 IEPR Mid case (16 gigawatts (GW) by 2030)
- Demand Response: Existing demand response programs remain in place
- Electric Vehicles: CARB Scoping Plan (3.6 million light-duty electric vehicles by 2030)
- Building Electrification: CEC 2016 IEPR Mid case

Supply Side

- Diablo Canyon Power Plant: retired in 2024/25
- Once-Through Cooling (OTC) Plants: retired according to State Water Board schedule
- Other Thermal Plants: remain online throughout the modeling period
- Existing Hydro & Pumped Storage: remain online throughout modeling period
- Storage Mandate: full storage mandate of 1,325 megawatts (MW) achieved by 2024
- RPS Resources: existing and contracted resources, once online, remain online throughout modeling period.

It is important to point out that the version of the model currently in use is only capable of optimizing primarily supply-side resources, including some DERs such as battery storage and some forms of demand response. Thus, energy efficiency, BTM PV, and some forms of demand response still must be input as assumed baseline resources that are not further optimized by the model's resource selection algorithm. Commission staff has handled this by running several sensitivity cases with different levels of demand, to account for the range of possible penetration of these demand-side programmatic resources.



The selected renewable resource categories and geographic renewable resource potential, in particular, build upon a great deal of the previous work of Commission staff in the RPS proceeding developing the RPS Calculator. The RPS Calculator has been used in previous RPS and long term procurement planning (LTPP) proceedings to inform both long-term generation and procurement planning, as well as policy-driven transmission planning as part of the TPP at the CAISO.

Another important note is that the model is structured based on individual technologies and their cost profiles, layered on top of their operating attributes such as contributions to spinning reserves, ramping capabilities, etc. Therefore, some technologies are substitutable for each other (e.g., several tranches of battery storage can be substituted for long-duration pumped storage, albeit at different costs) to fulfill the system integration needs.

We also note that during the course of this proceeding, SB 338 (2017, Skinner) was signed into law, which added a requirement to Section 454.52 that the commission consider the role of existing renewable generation, grid operational efficiencies, energy storage, and DERs, including energy efficiency, in helping to ensure that each LSE meets energy needs and reliability needs in hours to encompass the hour of peak demand for electricity, while reducing the need for new electricity generation resources and new transmission resources in achieving the state's energy goals at least cost to ratepayers. This requirement is implicit in the analysis conducted using the RESOLVE model; all of these existing clean resources and their attributes were taken into account in the modeling when the electricity reliability constraints were factored in to the analysis.

To make the model more user-friendly and to shorten run times, the model analyzes optimal portfolios for four representative years (2018, 2022, 2026, and 2030) rather than analyzing every year between now and 2030. In addition, the hourly integration needs are analyzed on a representative sample of 37 days of the year, and not in all 8760 hours individually. Thus, RESOLVE contains a simplified form of PCM, while also simulating capital investment decisions. The goal is to make it more useful for

the focus of the IRP analysis, which is capacity planning primarily for purposes of renewable integration and GHG emissions reduction.

After staff's initial analysis using RESOLVE, it became clear that implementing the 50% RPS requirement that is already in law, on its own, resulted in modeled electric sector emissions of approximately 51 MMT in 2030, before layering in any GHG emissions constraint. Since it appears, at this point in time, that there is a fairly widespread industry consensus that this level of RPS compliance is achievable and the state is on a path to achieve it, Commission staff elected to drop further analysis of the 62 MMT Scenario.

In addition, Commission staff recommended that the 50% RPS Scenario (constrained by the RPS requirement) become the default scenario against which other analyzed scenarios would be compared. It is important to note that this scenario also includes other statutory or regulatory requirements for storage, NEM, and demand response, but does not include a literal doubling of energy efficiency penetration in response to SB 350, in part because those energy efficiency targets had not yet been adopted by the CEC at the time the staff analysis was undertaken. In addition, the Commission was also considering the energy efficiency goals for the investor-owned utility (IOU) service territories in the energy efficiency rulemaking (R.13-11-005).

Because there was not yet an adopted energy efficiency target or widespread industry consensus, the Default Scenario included energy efficiency estimates (affecting the demand forecast) at approximately 1.5 times the 2015 AAEE level as adopted in the 2015 CEC's IEPR demand forecast. Since the proposed RSP was issued, the CEC has adopted the energy efficiency targets, but not yet the overall IEPR demand forecast, and the Commission has adopted the IOU energy efficiency goals.

In summary, the three GHG Scenarios ultimately modeled by Commission staff and for which results were produced are:

- **Default Scenario:** reflects existing policies, notably the 50% RPS, which is equivalent to statewide GHG emissions of approximately 51 MMT.

- **42 MMT Scenario:** the low end of the electric sector range estimated by the CARB Scoping Plan.
- **30 MMT Scenario:** reflecting electric sector emissions in the CARB Scoping Plan scenario where there was no Cap-and-Trade program assumed (though it has since been extended). In this scenario, the electric sector contributes more emissions reductions through direct mandatory measures; the study of this scenario reflects the uncertainty about relative costs and interactions between sectors.

Resource selection in the first scenario is driven by the 50 percent RPS requirement. The latter two scenarios are constrained not by the RPS requirement, but instead by the GHG emissions levels within the CAISO, by scaling down the statewide target to reflect the footprint of the CAISO grid. Selected resources beyond those included in the baseline are then optimized by RESOLVE. The selected electricity resource portfolios and their associated costs are presented in the results for the 42 MMT and 30 MMT scenarios, with resources presented in comparison to the baseline resources, and costs presented in comparison to the Default Scenario. It should be noted that there are additional costs required to accomplish the Default Scenario relative to current conditions in the electric sector; those costs are assumed to occur in all scenarios and are not reflected in the relative cost reporting comparing scenarios to each other.

In addition to these three major scenarios, Commission staff ran the model with changes to over 30 individual variables to test sensitivity to specific resource cost and benefit assumptions.

For all cases, total portfolio costs were estimated based on an incremental total resource cost metric, which is the measure usually used for estimating demand-side resource cost effectiveness. This metric takes into account fixed costs of new electric sector investments for generation and transmission, operating costs (including net purchases and sales), and utility and customer demand-side program costs. These costs are expressed in terms of annualized incremental costs over the course of the analytical time period (2018-2030) compared to the Default Scenario. Thus, the costs reported are not total costs, but rather total portfolio procurement costs, relative to the Default

Scenario. Not included in the cost comparison are previously-authorized costs not related to resource optimization in IRP (e.g., distribution infrastructure replacement and upgrade costs, general and administrative costs, etc.).

In general terms, to meet the Default Scenario constraints, the RESOLVE model selects a small amount of additional wind and battery storage and larger amounts of utility-scale solar capacity, by 2030. For the 42 MMT Scenario, the resource mix looks similar, with larger amounts of each resource chosen, plus a small amount of geothermal capacity. In the 30 MMT Scenario, the resource mix in 2030 changes by adding, in addition to larger amounts of wind, solar, geothermal, and battery storage: pumped storage.

In no scenario does the model pick new natural gas plants to be built in the future. The simplicity of this statement, however, masks some additional underlying complexity in the modeling results that may affect the economics of operation of natural gas plants that should be further examined and that is further discussed later in this decision.

The RESOLVE model is not designed to analyze individual natural gas plant dispatch impacts of various GHG constraints, because it handles categories or classes of plants and not individual plants by geography. However, Commission staff and consultants conducted some additional analysis to understand the impacts of the various GHG constraints on disadvantaged communities, both from a local air emissions and an economic development standpoint.

This additional analysis points out that a disproportionate number of existing natural gas plants are located in disadvantaged communities, as defined by those communities scoring in the top 25% according to the CalEnviroScreen Tool.

Staff analysis suggests that the choice of the GHG Scenario (42 MMT vs. 30 MMT) has a greater impact on the air pollution emissions in disadvantaged communities overall than any of the sensitivities containing changes to individual variables. This is generally because reducing emissions from the electricity sector requires more reliance on renewables and less on natural gas, with combined cycle

natural gas turbines being the most prevalent and largest emitters in the sector, since they run more hours than the peaking class of natural gas plants.

Similarly, the more stringent GHG Scenarios also resulted in a larger incremental renewable resource buildout in disadvantaged communities compared to the Default Scenario.

With respect to DERs, because most are not optimized intrinsically in the RESOLVE model, additional work is needed to be able to predict their value with specificity. However, we can say that in general, several DERs generally reduced total costs. Those include energy efficiency, shift demand response (flexible loads), flexible charging of electric vehicles, short duration storage, and time-of-use rates. Other DERs typically increased total costs, including BTM solar PV and shed demand response, unless there are specific local capacity needs.

There are several major factors, beyond just the basic resource costs assumed, that drive these overall results. First, curtailment of renewables is an integration option in the model. Curtailment is modeled by assuming that the developer is paid its production cost regardless of whether its output is curtailed or delivered to the grid; this is consistent with the terms of most current IOU RPS contracts. This curtailment alternative is lower cost than many of the more expensive renewable integration options for much of the time period analyzed. In the Default Scenario, the model predicts that curtailment would be approximately 3.2% by 2030, while it is 5.7% in the 42 MMT Scenario, and 7.3% in the 30 MMT Scenario. Staff also analyzed a “no curtailment” sensitivity, which shows that in order to avoid curtailment altogether, approximately 50 GW of additional storage would be required (in the 30 MMT Scenario) at a cost of nearly \$3 billion per year.

Second, the ability to take advantage of the federal investment tax credits (ITC) and production tax credits (PTC) in the near term, before they expire, to purchase solar and wind resources, results in the model selecting these resources earlier than they would otherwise be needed for RPS compliance or reliability purposes, and resulting in lower portfolio costs for ratepayers overall, though these assumptions do not take into account

some real-world implications, such as the fact that perhaps not all cost savings would be passed on to customers. The expiration and/or renewal of the ITC and PTC would affect the optimal timing for purchasing additional solar and wind.

This also interacts with the timing of the replacement of the power from the Diablo Canyon nuclear plant, because, rather than waiting until the plant is retired (assuming that occurs), the model essentially chooses to pre-purchase the solar and wind power that would otherwise be needed later in the next decade, in order to take advantage of the cost savings associated with the ITC and PTC. In other words, the replacement power in the amount of Diablo output is already being replaced by GHG-free resources prior to the retirement of the nuclear plant. And in all scenarios, the GHG emissions constraints in the CAISO area are met or exceeded.

Third, the modeling takes into account the amount of excess RPS procurement that has already occurred, particularly by IOUs, over and above the existing requirements, that can be banked and then used to demonstrate RPS compliance in the future. The use of this RPS procurement already banked has the effect of reducing the amount of additional renewable resources that are required to be developed in the future to meet a given RPS target; however excess RPS procurement does not affect the composition of the portfolio necessary to meet the 2030 GHG emissions constraint modeled in RESOLVE.

Fourth, new renewables in the modeling are not required to be fully deliverable with resource adequacy value, and may instead be paid on an energy-only basis. The Attachment A slide deck contains details about the amount of fully deliverable renewable capacity would be chosen relative to energy-only resources.

Fifth, constraints on both import and export capability between California and other states in the West, including assumptions about utilizing existing transmission, may affect the assumed geography of renewable resource buildout. This is also true of renewable buildout within California. That is, assumptions about utilization of existing transmission within California can also affect the modeled renewable locations in

California. These assumptions may or may not hold when actual procurement is conducted.

Finally, the model's assumption about the GHG emissions intensity of imports, which is based upon the value used by CARB in the Cap-and-Trade regulations, affects the predicted utilization of non-renewable resources within California between now and 2030, and results in a decrease in imports and an increase in California natural gas utilization, since the in-state plants generally have a lower emissions intensity. This may or may not reflect reality, depending on the trend over time in emissions produced by resources on the Western electricity grid overall.

In terms of costs relative to the Default Scenario, the 42 MMT Scenario is estimated by RESOLVE to cost approximately \$239 million more per year, in 2016 dollars. For the 30 MMT Scenario, the additional annual costs are estimated at \$1,137 million compared to the Default Scenario. The additional fixed costs are associated primarily with renewables and storage, with a small amount of additional transmission costs in the 30 MMT Scenario; cost savings are associated with the reduction in variable costs (primarily fuel costs).

The analysis was also designed to produce a RESOLVE output that estimates the marginal GHG abatement cost associated with a given GHG constraint. This number is referred to as the GHG Planning Price in the May 16, 2017 IRP Staff Proposal, and is designed to serve an objective planning function in the design of individual LSE IRPs. The GHG Planning Price is made up of the assumption about the Cap-and-Trade allowance price in each year (RESOLVE assumes a fixed Cap-and-Trade reserve price of approximately \$29 per metric ton of carbon dioxide equivalent (CO<sub>2</sub>e) in 2030) plus the incremental cost of reducing the marginal ton of GHG emissions to reach the GHG target constraint in the model.

The results of this analysis suggest that in 2030, the GHG Planning Price for the 42 MMT Scenario would be \$150 per metric ton of CO<sub>2</sub>e, while for the 30 MMT Scenario, the price would be \$283 per metric ton.

These GHG Planning Prices are then proposed to become inputs to cost-effectiveness analyses currently under consideration in the Integrated DER proceeding (R.14-10-003). These results would be available to replace the “interim GHG adder” values adopted in Decision (D.) 17-08-022 for use in the avoided cost calculator as a marginal GHG abatement cost, after the Commission renders a decision in this IRP proceeding.

With respect to the three resources selected by staff for special analysis (pumped hydro, geothermal, and out of state wind), the results suggest that out-of-state wind could represent a cost-effective means of diversifying the portfolio, assuming the cost assumptions used in RESOLVE modeling, if procured prior to the expiration of the federal PTC. Early procurement of pumped hydro and geothermal, on the other hand, would tend to increase total portfolio costs based on current cost estimates.

#### **4.4. Comments of Parties**

Numerous parties commented on the modeling analysis conducted by staff and its assumptions and conclusions described above. Those comments are divided into a number of categories and further discussed below.

##### **4.4.1. Baseline Resources**

Several parties felt that the baseline resource assumptions utilized by staff in conducting the modeling were generally reasonable, including SWPG, VEA, Tesla, SEIA, GridLiance West, and CESA.

Numerous parties took issue with the fact that the current version of RESOLVE did not model DERs as candidate resources to be optimized. Those parties included all of the IOUs, UCS, NRDC, EDF, and Vote Solar. NRDC and EDF also commented that locational benefits of DERs should be included in the analysis, while Vote Solar provided more detail on the need for temporal and locational granularity.

Several parties were also extremely concerned about the energy efficiency assumptions in the modeling, expressing the desire for the Commission to use the SB 350 statutory “doubling” requirement as the assumption. Parties disagreed, however, about



what the assumption should be, with CEJA and Sierra Club, as well as POC, arguing that the 2016 AAEE estimate from the CEC should be doubled, while BAMx and CCSF argued it should be double the sum of the AAEE and additional energy efficiency estimated as a result of AB 802, which modified the assumed baseline for energy efficiency savings. CEDMC asked that we display the energy efficiency results in the figures in the RSP. PG&E would like to see improvements in the cost estimates for energy efficiency.

Demand response assumptions were also questioned by some parties. BAMx and CCSF, as well as POC, would like to see shift demand response included in the baseline. EDF commented that time of use rates and shift and shimmy demand response products were given short shrift in the modeling.

For BTM PV, EDF felt that the forecasts were too low. CalWEA and GPI, meanwhile, felt that the default assumptions were too high.

For storage, CESA would have preferred to see 500 MW more of battery storage in the baseline. SoCalGas did not want any of the mandated 1,325 MW of storage in the baseline, because a self-generation incentive program evaluation showed that BTM storage can increase emissions. POC wanted lower cost assumptions for storage.

For electric vehicles, Tesla, SEIA, and EDF would have preferred to see a higher forecast of EV adoption.

On the supply side, the main concern was about the assumption that existing resources, both fossil-fueled and renewable, would be recontracted and available throughout the planning horizon to 2030. This view was shared by numerous parties to some degree, including PG&E, SCE, CEERT, UCS, AWEA, Calpine, CAISO, CalWEA, CESA, LSA, NRG, ORA, CAC, CBEA, Eagle Crest, GPI, National Grid, Range, and TransWest. CESA, POC, and Imperial County felt that early retirement of gas plants should be a default assumption. ORA suggested retiring gas resources and then making them available as candidate resources again in RESOLVE. Calpine conducted its own RESOLVE modeling that concluded that existing natural gas and geothermal plants are

economic and should be re-contracted. Range suggested that the re-contracting assumption may have biased the results against out of state resources and storage.

For renewables, CalWEA argued that pre-RPS renewable resources should not be included in the baseline with an assumption of re-contracting because many of those plants will be over 40 years old by 2030 and will need to be repowered by then. CalWEA therefore argues that the repowering option should be a candidate resource to be optimized by RESOLVE.

For CHP resources, CAC argues that the Commission should assume a five-year extension of the existing contracts. The IOUs, in their reply comments, argue against this suggestion.

Finally, for biomass facilities, CBEA argues that the costs assumed in RESOLVE are too high, though they acknowledge that it may not change the results because biomass costs would still be higher than geothermal. CBEA and GPI also point out that RESOLVE does not consider all avoided costs of biomass, such as avoidance of open burning of agricultural residue, diversion of biomass from landfills, and reduction of forestry waste. GPI also comments that biomass and biogas should be treated separately.

#### **4.4.2. Scenarios modeled**

Numerous parties were comfortable with the major scenarios modeled by staff. Those include SCE, AWEA, CalWEA, CEERT, CESA, LSA, Imperial County, NRG, ORA, Tesla, UCAN, GWT, VEA, SWPG, and TransWest. SCE noted that there may be some discrepancies between the Commission's results and CARB's that should be reconciled. UCAN supported the scenarios as long as LSEs can deviate from the require scenario with justification. CEERT felt that the range of scenarios was appropriate, but the modeling should be rerun to take into account differences with CARB's modeling that may impact long-lead-time resources such as geothermal.

Some parties took issue with the idea of the Commission modeling GHG reduction scenarios at all. SDG&E does not want the Commission to utilize a target, preferring to rely on the Cap-and-Trade program to produce needed emissions statewide. CalCCA

believes that the Commission does not have jurisdiction to set GHG targets, and that only CARB can do that.

Some parties disliked certain scenarios only. Defenders felt that it was unnecessary to examine the Default Scenario since it represents actions already likely to occur. Other parties preferred not to look at the 42 MMT and 30 MMT scenarios because they would place an undue burden on the electric sector relative to other sectors of the economy. Those parties include PG&E, Calpine, CMUA, BAMx, and CCSF.

#### **4.4.3. Cost assumptions and metrics**

Numerous parties commented on the manner in which resource costs are treated in RESOLVE. Staff used a total resource cost metric, which was favored by PG&E, SDG&E, NRG, ORA, and LSA. SEIA, POC, and EDF do not believe that the TRC approach is appropriate for BTM PV and/or storage.

EDF, Tesla, SEIA, SVLG, CalCCA, and Vote Solar all felt that benefits of DERs were undervalued in the model, including deferred transmission and distribution benefits, line losses, and transmission congestion costs.

SCE commented that the gas price assumptions in the model are too high. SCE, Calpine, and ORA would have liked to see the addition of fixed operating costs for existing natural gas plants, which would facilitate re-contracting being added as a resource to be optimized.

For storage costs, some parties felt they were assumed to be too low (National Grid), while other parties believed they were too high (CESA). Vote Solar and POC felt that solar PV cost estimates were too high.

IID commented that the assumed costs of geothermal resources were too high, while Ormat suggested the model costs did not reflect all values of geothermal, including avoided infrastructure costs, ability to provide ancillary services, higher capacity factors, full dispatchability, and physical durability.

Finally, Eagle Crest and National Grid commented that the assumptions about pumped storage led to its undervaluation, including the 12-hour duration assumption, failure to capture its long asset life, and failure to capture its full operational value.

#### **4.4.4. Curtailment as a grid integration strategy**

Many parties commented on the model's use of and results with high levels of renewable curtailment. The following parties generally support and agree with the use of curtailment as a grid integration strategy if it is cost-effective: PG&E, SDG&E, CEERT, CalCCA, BAMx/CCSF, LSA, ORA, TNC, Defenders. TNC and Defenders comment on the land use impacts and considerations.

The following parties generally object to emphasizing curtailment as a grid integration strategy: Tesla, UCAN, Eagle Crest, National Grid, Reid, CEJA, and Sierra Club. UCAN recommends further exploring the relationship between reliance on curtailment and customer rate impacts, while SCE is concerned about potential cost shifts among different types of customers. On a slightly different angle, LSA and NRG are concerned about cost shifting between resource owners and buyers.

POC is also concerned that curtailment not be used to enable continued operation of fossil fleets, with the associated impacts on disadvantaged communities. NRG is concerned that too much curtailment could jeopardize meeting the GHG goals, while SCE and CAISO are concerned about the potential detrimental effect on reliability. SCE and CAISO also worry that the model may underestimate the amount of curtailment needed, though NRDC is concerned that curtailment may be overestimated.

EDF would prefer that the Commission emphasize development of DERs that match demand, rather than relying on curtailment strategies. AWEA, TransWest, GWT, and VEA emphasize the value of a diverse portfolio. Ormat would like to see more geothermal, Trident more offshore wind, and SoCalGas more power-to-gas storage, to avoid additional curtailment.

CalWEA comments on the need for accounting for all costs of curtailment properly and having contract terms that reflect the appropriate value for curtailment

options. CMUA raises concerns about older renewable contracts and the ability to reflect curtailment, and Imperial County points out risks associated with the ability to continue to include curtailment terms in future contracts for wind and solar.

CESA acknowledges that curtailment may be a cost-effective strategy, but that it may waste the opportunity to utilize storage to provide the same benefits. Vote Solar points out that curtailment can be used in tandem with the ability of renewables to provide ancillary services to the grid.

Many parties also made comments about curtailment policy changes that should be pursued that were not strictly modeling related so they are discussed elsewhere in this decision.

#### **4.4.5. Banked RPS procurement**

A number of parties expressed concern about the treatment of the RPS compliance bank in the RESOLVE modeling. CalCCA, UCS, CAISO, AWEA, and CalWEA agree that the banked procurement should be reflected in the planning assumptions. However, many parties also argued that the bank should not serve to limit the amount of future procurement that is needed to achieve GHG goals. Those parties include AWEA, GWT, NRG, VEA, Vote Solar, SEIA, and TransWest. The IOUs, on the other hand, argued that their earlier procurement had already reduced future procurement needs and therefore the bank is important to represent.

A few parties were also concerned about the accuracy of the representation of the REC bank in the modeling, with the CAISO and ORA pointing out the need to represent that RECs can only have a maximum lifespan of 36 months, while IEP was concerned that the use of the bank may artificially inflate the GHG reductions associated with procurement that has already occurred. CalWEA also questioned the assumption that the bank would all be utilized before 2030.

#### **4.4.6. Import/Export Constraints and Assumptions**

A number of parties commented on the import/export constraints used by staff in the mode. GWT and VEA supported the staff approach. A number of other parties

agreed that 2,000 MW was the most appropriate export number in the absence of broader regional coordination, because the CAISO has never been a net exporter. Those parties include CAISO, CalWEA, AWEA, Eagle Crest, National Grid, TransWest and Vote Solar. Eagle Crest, however, felt that 8,000 MW as the upper bound assumption was too high.

Parties feeling that the export limits were too low in the model included SEIA, SDG&E, and Calpine, which commented that the limits should be tied to physical constraints and not historic levels.

The largest number of parties felt that more study is needed, including SCE, CalWEA, LSA, ORA, and CEERT.

Parties also commented extensively on the implications and effects of the various import and export constraints and assumptions, including the emissions factor associated with imported power.

#### **4.5. Discussion**

We acknowledge the thoughtful comments of all of the parties on the assumptions and analysis contained in the modeling. Many comments point to improvements that Commission staff intends to make for the next round of optimization analysis that will likely occur beginning in 2019. Commission staff plans to improve the modeling with the participation of parties as part of a public process, similar to this proceeding, where there are workshops and periodic informal work products.

In particular, staff anticipates conducting two types of improvements to the modeling: data updates and functionality improvements.

For data updates, staff anticipates modifying assumptions for all resource types based, at least in part, on results from any relevant solicitations, including utility-scale resources and DERs. Included in the updates could be new types of resources including compressed air storage and offshore wind. To the extent feasible, the updates will include cost information, including avoided transmission and distribution costs for DERs, as they become available.

Staff also anticipates updating the transmission costs and potential, land-use information, system requirements, local capacity requirements, avoided GHG and other air pollutant emissions from other sectors, and avoided GHG emissions related to the gas transmission and distribution system. There will also be new IEPR assumptions available.

For model functionality updates, staff will explore the following issues:

- Allowing existing resources to retire if not economical or uncontracted.
- Allowing the model to select existing, uncontracted resources as candidate resources.
- Including all DERs as candidate resources at appropriate levels of aggregation, including energy efficiency, shimmy demand response, BTM PV, electric vehicles, and building electrification measures.
- Modeling system operations by having load following reserve requirements respond dynamically do the resources selected by the model.
- Aligning GHG emissions calculations fully with the CARB accounting framework to ensure comparability.

For the current round of analysis, we are satisfied that Commission staff has utilized the best available assumptions and functionality, and has run enough sensitivity analyses that we can evaluate the impact of changes in certain assumptions to inform our decisionmaking and IRP framework.

The exact way we will utilize this modeling analysis and information is described further later in this decision, but we do emphasize here that the purpose of this analysis is to inform a directional GHG goal-setting framework for planning purposes, and the modeling does not lead to a direct compliance obligation for any LSEs at this stage.

## **5. Electric Sector 2030 GHG Emissions Targets**

The proposed RSP included a recommended assumption for the electricity sector's share of the 2030 GHG emissions targets. The selection of this target leads to the identification of the optimal portfolio and the calculation of the GHG Planning Price described further in Section 11 of this decision.

### **5.1. Staff Proposal**

In the proposed RSP, Commission staff recommended the 42 MMT Scenario as the most appropriate target for the electric sector for IRP purposes. There were a number of reasons for this recommendation. First, it was originally chosen because of its relationship to the January 2017 Draft Scoping Plan Update of CARB. The Default Scenario, constrained by the 50% RPS requirement, and representing the policy trajectory that the electric sector is currently on, generally represents the status quo, business-as-usual expectation.

The 42 MMT Scenario represents increasing momentum from current policies, including renewables, energy efficiency, storage, and a number of other initiatives, to push the most emissions reductions out of the electric sector without creating unreasonable costs. Although it is a middle case among those analyzed, it represents an approximately 50% reduction in GHG emissions from the electric sector from 2015 levels by 2030. This case includes aggressive pursuit of reductions in the electric sector, while also encouraging exploration of more cost-effective emissions reduction opportunities from other sectors, especially transportation, where the electric sector can also play an important role.

Commission staff also noted that the 42 MMT Scenario is roughly on the straight-line path toward the 2050 GHG target and the electric sector's contribution toward the statewide target, though acknowledged that more analysis of this GHG emissions trajectory is needed.

### **5.2. Relationship to ARB**

Since Commission staff originally selected the GHG Scenarios to be modeled based on CARB's January 2017 Draft Scoping Plan Update, CARB has revised its Draft Scoping Plan Update and a new version was adopted by its Board on December 14, 2017.



The range of emissions now identified for the electric sector is between 30 MMT and 53 MMT in 2030.<sup>12</sup>

However, as noted by Commission staff when the Proposed Reference System Plan was released, there is a 4 MMT accounting difference between how the Commission has accounted for the emissions from CHP facilities, which were not included as part of the electric sector but instead considered industrial emissions, and CARB's accounting methodology, which does count those emissions as part of the electric sector.

Thus, for purposes of comparison of electric sector emissions scenarios between the Commission's analysis and CARB's most recent estimates, our 42 MMT modeled scenario equates to 46 MMT within the CARB 30-53 MMT range for the electric sector.

### **5.3. Relationship to CEC**

As described in the May 2017 IRP Staff Proposal, we have consulted with the CEC about the proportion of the electric sector GHG target that should be met by Commission-jurisdictional LSEs relative to the publicly-owned utilities (POUs). LSEs participating in the CAISO represent approximately 80% of the load share of all electric retail providers in the state. To determine the responsibility of the CEC POUs and the Commission LSEs, a proportional share of the GHG emission was allocated according to the CARB Cap-and-Trade allowance allocation methodology for 2030. Thus the 42 MMT GHG target was divided in that manner as well, to determine the responsibility of the CAISO footprint for modeling purposes in RESOLVE.

### **5.4. Comments of Parties**

A long list of parties agrees with the staff recommendation for the Commission to use 42 MMT as the electric sector GHG planning target, including AEE, AWEA, CEDMC, CalWEA, CEERT, CESA, GWT, Reid, LS Power, LSA, NRDC, ORA, POC, SEIA, SVLG, SWPG, Tesla, TransWest, UCAN, UCS, and VEA. UCS points out that

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<sup>12</sup> See <https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm>.

the target should be revisited in each IRP cycle. CESA also argues that the 30 MMT case should continue to be evaluated for its benefits to disadvantaged communities.

The CAISO conditionally agrees with the 42 MMT scenario, because it is consistent with other state policies. Ormat agrees on the condition that a different cost range for geothermal projects should be used in the analysis. Vote Solar would prefer to see additional analysis of the 30 MMT and posits that it is likely to be less expensive than assumed, because of the impact of DERs and economies of scale in that realm.

SCE says they disagree with the 42 MMT recommendation, but could support it if several issues with the analysis are resolved, including fully integrating all supply and demand resources, accounting for cross-sector opportunities, and reforming cost allocation mechanisms to prevent cost-shifting among LSE customers. SCE also specifically focuses on transportation electrification and its potential to create a disincentive to GHG reductions unless the associated increased load is not attributed to electric LSEs in meeting their GHG targets.

Several parties would prefer a less stringent assumption for the 2030 GHG target for the electric sector.

PG&E proposes a 46 MMT target,<sup>13</sup> which they believe is better aligned with CARB's Scoping Plan and its Cap-and-Trade market assumptions, enabling more cost-effective reductions across sectors. SDG&E believes that the 42 MMT target puts too great a burden on the electric sector relative to other sectors of the economy. In particular, SDG&E is concerned that the associated GHG planning price is too high. SDG&E also does not generally support a single year target, because it fails to account for reductions achieved through early actions and is not fairly applied to POUs outside of the Commission's jurisdiction.

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<sup>13</sup> PG&E's proposed 46 MMT target would correspond approximately to a 50 MMT target under the CARB accounting framework.

CAC prefers that the Commission use the Default Scenario for planning purposes, since many of the reasons staff gave for supporting 42 MMT could be equally applied to the Default Scenario, which is already aggressive.

CalCCA states that the Commission should focus on achieving the identified emissions reduction measures and not picking a particular GHG target. CMUA also prefers utilizing CARB's planning range without picking a single target and using it to apply to individual LSEs. NRG and SoCalGas feel that more cost-effective GHG reductions may be available in other sectors, a sentiment generally shared by a number of other parties.

Several parties would prefer that the Commission adopt a more stringent planning target, such as between the 42 and 30 MMT Scenarios, the 30 MMT Scenario, or an even more aggressive target.

Eagle Crest feels that the Commission should be more aggressive because there is still heavy reliance on gas-fired generation through 2030, creating an obstacle to the development of additional GHG-free resources needed over the long term. EDF is concerned that the benefits of DERs are not fully reflected in the analysis and thus the Commission should be more aggressive than 42 MMT.

A number of parties favor the 30 MMT Scenario because it has the most beneficial impact on disadvantaged communities, including CEJA and Sierra Club, IID, Imperial County, and Range. CEJA and Sierra Club state that they would accept the 42 MMT Scenario if it was modified to reflect a true doubling of energy efficiency savings, lower storage costs, and prioritization of disadvantaged communities by focusing on retirement of gas-fired resources to minimize air pollution.

## **5.5. Discussion**

We intend to adopt the staff recommendation of the 42 MMT Scenario for planning purposes for the first round of IRP filings from LSEs. As noted earlier, this is equivalent to a 46 MMT assumption when compared with the 30-53 MMT range identified for the electric sector in the most recent Scoping Plan Update adopted by

CARB. Further details about how this assumption should be used by individual LSEs in their IRP filings are included later in this decision.

We adopt the 42 MMT Scenario as the planning assumption for the electric sector for a number of reasons. First, while it is at the upper end of the range identified by CARB, it still represents an increase in momentum relative to current policies and activities already underway. For example, it would represent achieving somewhere between 53-57% renewables by 2030, without creating overly burdensome costs for the sector that would be represented by the 30 MMT Scenario.

The 42 MMT Scenario is also not so burdensome to the electric sector to create major disincentives toward electrification, as SCE and others are concerned about. We do agree with SCE that more analysis is needed to set targets and encourage cross-sector GHG reduction opportunities, including electrification. While this may become a major portion of our analysis in future IRP cycles, for this first cycle we agree with staff's initial focus on the electric sector, in order to ensure that our own house is in order before taking on additional responsibilities. We are mindful of SCE's comments about the potential for creating disincentives toward lower-cost GHG reduction opportunities through electrification, and intend to focus more analysis on these issues in the future.

For the analysis we have before us today, however, the Default Scenario represents business as usual, and we believe that the electric sector can go further without creating undue cost burdens.

Though the 30 MMT Scenario is appealing for some of its impacts, including positive air quality and economic benefits in disadvantaged communities, it represents too high a cost burden for the electric sector relative to other sectors of the economy. We also emphasize that the 42 MMT Scenario is a planning target, and that the Cap-and-Trade program is the ultimate compliance tool for ensuring a direct reduction in GHG emissions economy wide in California. While the 42 MMT scenario planning target represents a slightly disproportionate share of responsibility on the electric sector, we have a number of resources that require lumpy investments and/or long lead times to

come to fruition. Thus, there is some hedging value in planning for a slightly more stringent target in the event that some of the anticipated activities associated with that target may prove harder to achieve or may take longer than anticipated.

As recommended by several parties, we also intend to revisit this target in each IRP planning cycle. Although the 42 MMT Scenario will be the planning assumption for the 2030 target for individual LSE IRPs to be filed in 2018, LSEs will only be proposing any necessary procurement required in the forthcoming 1-3 years after the IRP approval. Thus, all actions to achieve the 2030 targets will not take place in each planning cycle. Rather, the GHG target will point the direction and trajectory that can be adjusted when more information becomes available after each two-year cycle, either through better assumptions, improved analytical modeling functionality, and/or actual procurement experience.

## **6. Disadvantaged Communities Analysis**

This section addresses the analysis conducted by Commission staff with respect to the impact various scenarios examined as part of the selection of the optimal portfolio may have on disadvantaged communities. The analysis conducted built upon the many thoughtful comments offered by parties in response to the December 2016 Assigned Commissioner's ruling on disadvantaged community issues, as well as comments submitted in response to the May 2017 ALJ Ruling on the IRP Staff Proposal. Comments focused on a number of issues, including defining the term "disadvantaged community," possible requirements and metrics to address impacts on disadvantaged communities, consequences of failing to demonstrate meeting a requirement, consideration of disadvantaged communities in procurement-related activities, and coordination between agencies and among Commission proceedings on issues that impact disadvantaged communities.

### **6.1. Staff Analysis**

In order to define disadvantaged communities for purposes of further work in the IRP context, Commission staff recommended disadvantaged communities be defined as

those scoring above the 75<sup>th</sup> percentile using the CalEnviroScreen tool created by the California Environmental Protection Agency (CalEPA).<sup>14</sup>

As part of the RESOLVE modeling, staff conducted additional analysis to understand the potential impacts of the various scenarios on disadvantaged communities. Because existing natural gas plants are located disproportionately in disadvantaged communities, there is a nexus between analysis of natural gas resources and disadvantaged communities impacts.

In no scenario analyzed by staff did the model pick new natural gas plants to be built in the future. However, the RESOLVE model is not designed to analyze the individual natural gas plant dispatch impacts of various GHG constraints, because it handles categories or classes of plants and not individual plants by geography. Thus, Commission staff and consultants conducted some additional analysis to understand the impacts of the various GHG constraints on disadvantaged communities, both from a local air emissions and an economic development standpoint.

The results of this analysis suggested that the choice of the GHG Scenario (42 MMT vs. 30 MMT) has a greater impact on the air pollution emissions in disadvantaged communities overall than any of the sensitivities containing changes to individual variables. This is generally because reducing the emissions from the sector requires more reliance on renewables and less on natural gas, with combined cycle natural gas turbines being the most prevalent and largest emitters in the sector, since they run more hours than the peaking class of natural gas plants.

Similarly, the more stringent GHG Scenarios also resulted in a larger incremental renewable resource buildout in disadvantaged communities compared to the Default Scenario.

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<sup>14</sup> For ease of reference and consistency of terminology, this will be referred to as the “top 25 percent” throughout this decision.

Staff also proposed that each LSE be required, in its IRP, to describe the disadvantaged communities it serves, as well as the manner in which the LSE plans to meet the requirements of SB 350. In particular, staff suggested that each LSE be required to describe how it will plan for early priority on disadvantaged communities both for reducing GHG emissions (and associated local air pollutants) and for increasing local economic development opportunities for clean energy. Each LSE would also be required to describe its evaluation criteria for resource selection during the procurement process, if procurement is proposed, with factors addressing issues of concern in disadvantaged communities.

## **6.2. Comments of Parties**

Numerous parties commented on the definition of disadvantaged communities included in the May 2017 IRP Staff Proposal to use the top 25% of the communities as defined in CalEnviroScreen. Parties generally in support of this definition included CEJA, Sierra Club, GRID, Liberty Utilities, ORA, SCE, and SDG&E.

GRID also suggested using Section 2852 compliance as a foundation to identify low-income communities for secondary prioritization in IRP. Liberty was concerned that having a different definition in IRP than in some other programs could create uncertainty across multiple programs that address disadvantaged communities. SCE's comments supported the definition but emphasized that none of our proceedings should rely only on a single metric to guide program development.

GRID and ORA pointed out that the definition could be applied on a statewide basis or by utility service territory, with both preferring a statewide application, while ORA acknowledged that it could create a disproportionate impact in a particular utility territory. Imperial County also focused on ensuring a statewide application of the standards.

Parties generally in opposition to the definition included GSPC, CalCCA, AReM, CESA, Reid, PG&E, and Imperial County.

AReM and CalCCA focused on the argument that any disadvantaged communities requirements cannot be applied to them because, in the case of ESPs, AReM argued they don't have "service territories," and in the case of CCAs, CalCCA argued that their governing boards will decide disadvantaged community needs.

GSPC commented that although rural communities are disadvantaged, they typically do not appear in the top 25 percent using the CalEnviroScreen tool. CESA generally agreed. Thus, GSPC argued that the IRP definition should be expansive, allowing LSEs to include qualitative descriptions of demographics and how they are addressed.

Reid argued that the CalEnviroScreen tool is inconsistent with state law because it does not address income level, unemployment rates, home ownership rates, rent burdens, or educational levels.

CESA was concerned that the CalEnviroScreen tool has data limitations and marks various census tracts "not applicable" because of a lack of complete data.

PG&E commented that the recommended tool prioritizes a subset of disadvantaged communities by joining environmental concerns with adverse socioeconomic indicators in an awkward manner, creating funding prioritization that may not match burden.

The following parties were generally in support of the staff analysis and proposed general requirements for individual IRPs: CEJA and Sierra Club, CESA, IID, Reid, LSA, ORA, SCE, Tesla, UCAN, UCS, and Vote Solar.

CESA's comments pointed out that the disadvantaged community considerations are more easily and appropriately addressed when LSEs procure, rather than in the planning stage of IRP.

IID's comments were focused on the benefits of development of geothermal resources in the state, both for disadvantaged community economic development as well as GHG and local air quality impacts.



SCE's comments generally supported the idea of addressing both system-wide GHG emissions goals and local air quality impacts, especially focusing on electrification of transportation and building end uses.

UCAN felt that individual LSEs are best positioned to analyze the impact of their IRPs and procurement on their local disadvantaged communities. Vote Solar also commented that the credibility of individual LSE IRPs will depend on their treatment of disadvantaged community impacts.

Numerous other parties disagreed with the recommendations by staff, including AReM, CalCCA, EDF, Imperial County, National Grid, NRG, PG&E, SDG&E, and SoCalGas.

AReM's objection is that any disadvantaged communities-related requirements should not apply to ESPs. AReM argues that such evaluation criteria does not apply to their resource selection, and that because their customers pay their share of public purpose program charges and other non-bypassable charges, no other demonstrations should be required of non-IOU LSEs.

CalCCA supported the disadvantaged communities concepts, so long as they are implemented on a voluntary basis.

EDF objected to the staff recommendations because they do not go far enough to address the fact that disadvantaged communities suffer disproportionately from the impacts of poor air quality. Imperial County also would like a more robust framework including requirements for compliance.

National Grid pointed out that electric sector emissions are small in comparison to the transportation sector, and thus more cross-sectoral benefits, particularly around electrification, should be required. NRG also thought the analysis was too narrow, focusing only on the electric sector, and that could produce inefficient or even counter-productive results.

The IOUs were generally concerned about the impact on costs of inefficient requirements, arguing they should be analyzed thoroughly before implementation. They

also argued that the benefits of all of the other programs that the IOUs already run for disadvantaged communities should be recognized.

Parties also had numerous suggestions for additional or augmented requirements for disadvantaged communities issues in the IRPs.

CEJA and Sierra Club were concerned with ensuring that we appropriately define disadvantaged communities in this context. They requested that we give specific direction to LSEs on: 1) prioritizing natural gas retirements to minimize air pollution, 2) requiring preferred procurement of DERS and storage in DACs, 3) considering the impact of natural gas plant cycling within IRPs, and 4) adopt interim procurement guidelines for consideration of air quality. They also suggest that LSEs track air emissions from facilities that provide generation to their customers to ensure that the IRPs actually minimize pollutants.

UCS made comments similar to CEJA/Sierra Club, suggesting that LSEs be required to analyze how to reduce natural gas plant cycling in a way to reduce local air pollution, as well as include information about the amount of GHG emissions and air pollutants associated with gas generation to serve their customers.

EDF was concerned about the lack of granularity of the DER analysis in RESOLVE, leading to an inability to analyze locational benefits. They urged additional attention to this issue with particular emphasis on DER siting in beneficial areas.

Imperial County commented that the disadvantaged communities analysis required by SB 350 will ultimately require a qualitative judgment by the Commission about whether individual IRPs meet the disadvantaged communities requirements in balance with other requirements.

ORA argued essentially the opposite, that the Commission should develop quantitative metrics, including those developed possibly as part of the common resource valuation methodology (CRVM), to assess procurement impacts in disadvantaged communities.

LSA pointed out the benefits of solar development in disadvantaged communities, while Eagle Crest argued that development of pumped storage would reduce need for reliance on natural gas plants. Tesla argued that transportation electrification plans by LSEs should be included in the IRPs, where appropriate.

### **6.3. Discussion**

As proposed by Commission staff, for purposes of the requirements of SB 350 to address disadvantaged communities impacts in the IRP process, we will define disadvantaged communities as those that score at or above the 75<sup>th</sup> percentile in the CalEPA's CalEnviroScreen 3.0 on a statewide basis.<sup>15</sup> This definition has the advantages of being readily available, widely recognized, and simple to administer on a statewide basis. LSEs may choose to address communities they are concerned about beyond those included in this definition, but they will not be required to do so in their IRP filings.

We will also require each LSE to address in its individual IRP how it will address impacts on disadvantaged communities. There is no justification for CalCCA and AReM's positions that these requirements should be voluntary or nonexistent for non-IOU LSEs. Section 454.52 clearly requires the Commission to "ensure that load-serving entities do the following: (F) strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities... and (H) minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code." ESPs and CCAs are not exempted, nor are we persuaded that they should be.

ESPs and CCAs are a bit differently situated, however. ESPs may not serve contiguous "territories" or geographic areas the way IOUs and CCAs do, but they should be able to easily identify not only the location of the customers they serve, but also the location of the generation sources they buy power from to serve those customers. This

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<sup>15</sup> <http://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30>.

analysis is easier for CCAs, and easiest for IOUs. But all LSEs shall address the disadvantaged communities requirements in their IRP filings.

At a minimum, all LSEs shall provide the following information in their IRPs:

- i. A description of which disadvantaged communities, if any, it serves (LSEs will be expected to make the determination of what is considered “disadvantaged” every two years)
- ii. What current and planned LSE activities/programs, if any, impact disadvantaged communities
- iii. A qualitative description of the demographics of the customers it serves and how it is currently addressing or plans to comply with the requirement to minimize air pollutants.

In addition, as we discuss later in this decision, we expect that some LSEs will conduct PCM of their IRPs, and likely smaller LSEs may not. For those who do conduct PCM, we will require that they include information in their IRPs about the detailed GHG and local air pollutant emissions (at least nitrogen oxides and particulate matter) associated with all of the emitting resources in their portfolios, with separate accounting for resources located in disadvantaged communities. Entities not conducting PCM should still provide best available estimates for this information. For those resources located in disadvantaged communities (existing owned resources, contracted resources, or planned new resources), we expect disclosure of the following information, at a minimum: annual emissions of GHGs, annual emissions of local air pollutants (nitrogen oxides and particulate matter, at a minimum), and number of annual starts. Emissions reporting shall also include emissions due to cycling, in addition to emissions from normal operation.

Likewise, for non-emitting resources, we expect disclosure of locational information, including whether it is proposed to be located in a disadvantaged community.

In addition, all LSEs who propose to conduct procurement activities either for the development of new resources or re-contracting of existing resources, must describe their planned activities to conduct outreach and seek input from any disadvantaged

communities that could be impacted by the procurement. The LSEs must identify specific issues of impacts on disadvantaged communities and describe any environmental justice issues identified by residents and organizations within the disadvantaged communities.

LSEs also must implement evaluation criteria with respect to generation or storage resources located in disadvantaged communities. LSEs must describe their planned evaluating criteria, including any scoring bonuses or other approaches to ensure “early priority” as required by the statute. LSEs must then, at the time of procurement, demonstrate that they followed the identified criteria.

Finally, because of the clear nexus between natural gas generation and emissions in disadvantaged communities within the electric sector, we will require that any LSE proposing to develop new natural gas resources or re-contract with existing natural gas resources in their IRP, regardless of whether it is located in a disadvantaged community, make a showing as to why another lower-emitting resource could not meet the need identified.

We also appreciate a number of parties’ suggestions for improving the disadvantaged communities analysis in IRP, which we will consider in the next round. In particular, we agree with those parties focusing on the potential benefits and synergies associated with electrification of transportation and buildings for disadvantaged communities. This promises to be an important topic for the next RSP, after we address the first round of IRP filings from LSEs in 2018.

## **7. Long Lead-Time Resources**

### **7.1. Staff Analysis**

In addition to the numerous modeling sensitivities designed and run by Commission staff, staff also selected three particular resources to study in greater detail, because of their unique characteristics and the long lead times potentially necessary for their development. These analyses were done to further illuminate the potential value

and risks associated with procuring these resources in the near term (next 1-3 years).

They are:

- Pumped storage
- Geothermal
- Out of state wind.

To test the results related to these types of resources, staff manually forced the model to accept certain amounts of these resources in the earliest possible timeframes associated with their development timelines, to identify the impact on cost and value to the portfolio overall.

With respect to pumped storage and geothermal, staff concluded that there is enough lead time before 2030, under the 42 MMT Scenario, that procurement activities do not need to begin in this IRP cycle. These resources can be examined again with better information in the next IRP cycle.

For out-of-state wind resources, staff recommended beginning specific further study of the resources as one of the five Commission policy actions associated with the proposed RSP, in coordination with CAISO.

One option recommended by staff to direct further analysis of the out-of-state wind and associated transmission was to transmit the special portfolio modeled for this purpose to the CAISO for a “special study” under its TPP, or in addition to it, for 2018. A special study analysis would not result in transmission investments in this TPP cycle, however.

A second option identified by staff would be for the Commission to transmit a request for the study of out-of-state wind options as part of the policy-driven scenario for the TPP, in order to allow for study of transmission investments that could be approved before 2020. In order to accomplish this, additional analysis would be required to identify the geographic areas to be studied based on the likely renewable portfolios, since the RESOLVE analysis so far was constrained by a lack of detailed information about the most cost-effective combinations of new transmission infrastructure and wind resources.

## **7.2. Comments of Parties**

When staff proposed these three specific resource studies, several parties commented on the design of the studies in the June 28, 2017 comments, which improved the ultimate analysis conducted. Parties generally supporting the specific analyses included AReM, CAISO, CEERT, Imperial County, Reid, LSA, National Grid, ORA, Pathfinder, SWPG TransWest, and UCS. SDG&E suggested allowing the model to pick different increments and durations of pumped storage. Pathfinder and CHBC both suggested considering other types of bulk storage, and actual projects.

PG&E disagreed with conducting a separate geothermal study, suggesting that it does not face any specific market barriers. Defenders recommended including a particular focus on geothermal in Imperial County for dedicated study. GridLiance suggested adding consideration on resources in Nevada, in addition to Wyoming and New Mexico.

Parties also commented on the results of the three resource studies. The following parties generally agreed with all the results: LSA, AWEA, Vote Solar, CEJA and Sierra Club, and Reid. LSA also commented that the costs of out-of-state wind may be understated in the study. NRG agreed that based on the results, there is no reason to pursue near-term procurement of these resources, but results could be different if the natural gas assumptions in the baseline were different.

Vote Solar commented that it was a good idea to look at these resources separately, but that there should be no special procurement carve-out for them. Tesla pointed out that the risks of these large-scale investments should be weighed against the diversity benefits of DER procurement, with particular concern about pumped hydro storage.

Some parties made comments supportive of resource diversification more generally, including CAISO, CEERT, and GPI.

PG&E, SCE, ORA, and TransWest agreed that the results show no need for extra geothermal investment, with ORA suggesting evaluating this question again in the next IRP cycle.

Other parties offered more nuanced views on the geothermal results. Defenders supports additional geothermal development. Calpine conducted its own RESOLVE modeling to demonstrate that existing geothermal projects are cost-effective, even though new development may not be in the short-term. Ormat also ran its own RESOLVE case, with lower geothermal costs, demonstrating that additional geothermal would be selected by the model. Imperial County commented on the hedge value of geothermal because of its diversity relative to the rest of the renewable portfolio. GWT and VEA also commented that staff should have considered Nevada geothermal as well as California.

PG&E, SCE, ORA, TransWest, GWT, VEA, TNC and Defenders agreed that the results show no need for near-term investment in pumped storage, with TNC and Defenders suggesting caution with respect to potential ecological damage from pumped storage.

CESA commented that pumped storage may have been undervalued in the modeling due to the lack of representation of costs associated with maintaining the existing gas fleet and after accounting for a likely longer useful life. CESA also requests that the Commission acknowledge that bulk storage resources require a different procurement pathway from the current storage solicitations to meet the 1,325 MW storage mandate. Range commented that the selection of bulk storage in the 30 MMT case suggests that the Commission should continue to conduct studies like this in the future, because different assumptions lead to different results.

Eagle Crest commented that it would be unrealistic to build pumped storage in 2022, and that “forcing in” pumped storage should be studied with 2026 as the target year. They also felt that the life of the storage asset should be lengthened in the study. Finally, National Grid disagreed with the pumped storage results and suggested a closer look at out-of-state wind from the Pacific Northwest instead.



Out-of-state wind resources received special focus in October 2017 comments and workshop discussion because staff suggested additional Commission policy action in this area as part of the proposed RSP.

Numerous parties supported further study of out-of-state wind resources, to varying degrees, with some suggesting procurement of the resources beginning in 2018, to take advantage of expiring federal PTC. AEE would also like the option to develop transmission associated with out-of-state wind development. CalWEA agrees and wants procurement action, not just further study, a view shared by Pattern. GWT would like Nevada resources included, while National Grid suggested wind from the Pacific Northwest. SWPG agreed that procurement activities should commence quickly to allow federal PTC benefits to be captured. SWPG also requested that the Commission move to eliminate barriers to LSEs signing contracts with out-of-state resources. VEA also supported mandatory procurement to take advantage of federal PTC benefits, and stated it should not be limited to Wyoming and New Mexico.

AWEA would like the RSP to serve as a policy driver for new transmission investment in 2018-19, and the Renewable Energy Transmission Initiative (RETI) 2.0 Western Outreach Planning Report should be the basis for identifying the granular scenarios.

CEERT wanted the Commission to expedite cost and need determination to allow out-of-state resources to be an option to be procured.

LS Power commented that there may be additional transmission capacity with the retirement of coal plants, and wanted the Commission to better understand the diversity benefits of out-of-state wind. They suggested that detailed analysis of multiple combinations of transmission and general options should be done to find a least-regrets transmission path.

CalCCA supported further study, but opposes mandatory procurement by LSEs. SCE similarly recommended further study, especially of the aggregate effect of out-of-

state resources on transmission lines, not just wind. They also felt that more information is needed about costs to determine the value of out-of-state wind.

CAISO suggested that the Commission require the LSEs to conduct a Request for Information to gauge commercial viability of projects. The results of this process could be used to develop packaged generation and transmission solutions. CAISO felt that a special study would not be helpful, but instead further CAISO action would be through its Federal Energy Regulatory Commission Order 1000 transmission development process after LSEs have proposed out-of-state resources in their IRPs and the Commission has approved them as part of the PSP.

Defenders was concerned about potential impacts on wildlife habitat from expanding transmission, and urged coordination with other responsible agencies.

EDF's comments focused on the possibility of a regional market in the future, allowing comprehensive out-of-state resource competition to serve California needs.

SDG&E supported adding out-of-state to the preferred portfolios, and inclusion in the TPP.

TransWest urged further work to support out-of-state wind resources, especially those in advanced development and already studied as part of RETI.

UCS supported initiating activities to further investigate potential benefits, including a possible hedge against solar PV cost volatility. They also commented that the Commission should identify how current RPS content categories could be modified to facilitate development of out-of-state wind for RPS compliance.

VEA and Vote Solar also supported procuring additional out-of-state wind resources and transmission.

Many other parties were opposed to the Commission considering additional study or procurement of out-of-state wind resources at this time.

BAMx commented that this TPP cycle is premature for study and authorization of additional transmission. Any additional study should be informational only.

CEJA and Sierra Club preferred that the Commission wait until after approval of the PSP before investigating out-of-state wind further.

CMUA felt the Commission should not presuppose results and potential benefits solely based on the RESOLVE analysis.

IID advocated that all renewable development should be kept within California, with special focus on geothermal in the Imperial Valley to replace natural gas. IID viewed any discussion of out-of-state wind benefits as a “regionalization Trojan horse.”

LSA felt that out-of-state wind is not effective without additional transmission, which will raise costs.

POC argued that there is no need to pursue out-of-state wind when all of the necessary benefits can be achieved with a diverse portfolio of California resources.

ORA supported further study but noted that out-of-state wind was not significantly more cost-effective than in-state wind and is not part of a least-cost portfolio.

Imperial County supported coordination with the CAISO, but cautioned against assuming cost-effectiveness of out-of-state resources because of the transmission cost uncertainty.

PG&E suggested it was premature to accelerate procurement of out-of-state wind resources because it would increase costs. However, they supported further study in the next IRP cycle.

TURN supported California LSEs remaining open to considering bids from out-of-state resources in procurement processes, but did not believe that projects requiring additional transmission upgrades would be beneficial at this time.

### **7.3. Discussion**

We agree with Commission staff identification of pumped hydro storage, geothermal, and out-of-state wind resources as appropriate for extra study and focus. All of these resources require, to varying degrees, long lead times and/or large capital investments. They may also require a large amount of load and/or aggregated purchases by multiple LSEs to be considered economic.

Depending on the progress of our GHG mitigation strategies and our renewable integration needs, all three of these resources may prove necessary for reliability and/or economic reasons for the state by 2030. Thus, it will be important to continue to evaluate their costs and benefits in each IRP cycle.

We should note that, in the case of pumped hydro storage and out-of-state wind, these technologies in the resource studies can act as proxies for other similarly situated resources. Out-of-state wind may be generalized to include all out-of-state renewables, though wind adds a specific diversity benefit relative to in-state wind and solar resources. Pumped hydro storage can also be generalized to include bulk storage of other types.

We will continue to study all of these resource types in the next cycle of IRP, to determine if circumstances and cost/benefit assumptions have changed sufficiently to reach a different conclusion about the need for near-term procurement actions. For this cycle, we are satisfied that we do not need to direct immediate activity to support additional geothermal development, pumped hydro storage development, or out-of-state wind development, outside of what would naturally occur during LSE-specific procurement activities.

We further discuss the impact of potentially-expiring federal tax credit benefits later in this decision.

## **8. Reference System Portfolio**

The Reference System Portfolio is represented by the new and existing electricity resources chosen by RESOLVE under the 42 MMT Scenario we are adopting for the electric sector for 2030.

### **8.1. Staff Recommendation**

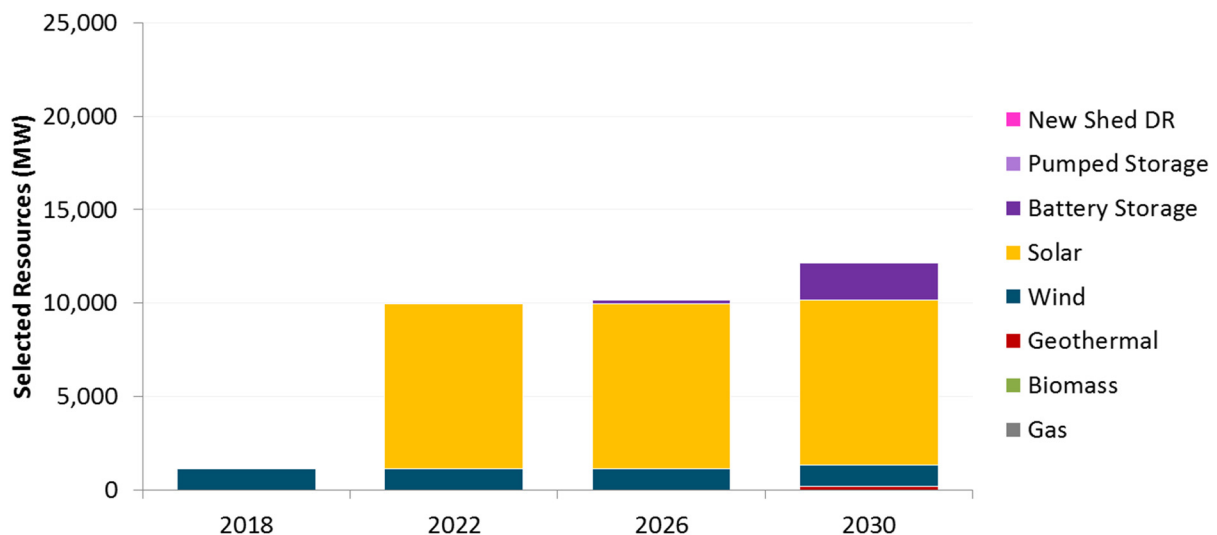
Since the 42 MMT Scenario was recommended as the preferred case for planning purposes for LSE IRP filings, the associated optimal resource portfolio was also recommended as the example portfolio against which the LSEs should compare their individual resource plans.

In 2030, the RESOLVE model selects an incremental set of resources, in addition to the baseline quantities of energy efficiency, demand response, storage, renewables, hydro, natural gas and nuclear, including the following (with the proportionate percentages of the total new resources selected by the model in parentheses):

- 200 M W of geothermal (1.6%)
- Approximately 9,000 MW of utility-scale solar (73%)
- 1,100 MW of in-state wind (9%)
- 2,000 MW of battery storage (16.4%), incremental to the 1,325 MW already required, the need for some of which could be displaced by certain types of advanced demand response and/or pumped storage.

These resources are depicted in Figure 2 below.

**Figure 2. Recommended Portfolio of Additional Supply Resources, Beyond Baseline, to Meet 42 MMT Planning Target**



Staff proposed that the LSEs should use the reference system portfolio to prepare their individual IRPs by filing “conforming portfolios,” as well as “preferred portfolios” that explain and justify any deviation from the RSP portfolio.

Conforming portfolios would be defined by demonstrating consistency with the reference system portfolio by 1) either using the GHG Planning Price or the LSE-Specific 2030 GHG emissions benchmark and 2) using input assumptions matching those used in

developing the reference system portfolio, with some updating to reflect the latest IEPR assumptions.

A “preferred portfolio” would be designated by the LSE as the portfolio most suitable to its own needs, while justifying and explaining any deviations from the conforming portfolio.

## **8.2. Comments of Parties**

A number of parties generally supported the portfolio identified by Commission staff, including CalWEA, LSA, Defenders, NRDC, VEA, and GWT. A number of parties are also supportive, with the caveat that the reference portfolio should inform LSE planning, but not be required to be strictly adhered to. ORA, CEERT, and UCS make this point.

Another set of parties could be described as ambivalent or conditionally supportive of the reference portfolio. AWEA suggested using the unconstrained out-of-state wind case as a basis for planning to capture near-term tax-credit procurement, as well as fully considering expiring contracts and re-contracting potential.

BAMx and CCSF are concerned about the potential for over-procurement of renewables at significant cost, based on the reference portfolio. CalCCA is also cautious and suggest that the Commission fully evaluate the ratepayer impact of potential near-term procurement.

The CAISO had concerns about the reference portfolio because it has not yet been subjected to PCM for reliability analysis. They are also concerned about how individual LSE responsibilities will be assigned if there is a reliability shortfall to meet the recommended portfolio. Range and Tesla made similar points.

Imperial County would like to see at least 500 MW of geothermal included in the portfolio, and CESA recommended using the low battery cost assumption with faster-than-anticipated natural gas resources.

Some other parties felt that the portfolio is not ambitious enough. CEJA and Sierra Club felt that the portfolio does not meet all of the SB 350 requirements, in

particular related to disadvantaged community impacts, as well as a diverse and balanced set of resources leading to resilience and sustainability of the bulk transmission and distribution systems. EDF opposed the portfolio recommendation because it does not contain enough DERs or accurately reflect their value to the system. Eagle Crest opposed because the portfolio should include pumped storage. TransWest felt that the portfolio should include out-of-state wind and associated transmission upgrades. SoCalGas would like to see power-to-gas projects and renewable gas technologies included in the portfolio.

On the other end of the spectrum, some other parties opposed the portfolio recommendation because it is too ambitious or based on what parties believe are incorrect assumptions in the model. Among these parties are all of the IOUs, for various reasons. SCE was concerned about the lack of optimization of demand-side resources leading to over-reliance on supply. PG&E was concerned that there is too much assumed reliance on the IOUs to procure on behalf of the entire system, at least without cost recovery policy modifications.

Ultimately, numerous parties, including the IOUs, NRG, National Grid, and LS Power, opposed the reference portfolio because they believe that optimized individual LSE portfolios will look substantially different than the reference portfolio, and individual LSEs should be given the flexibility to determine that in their own planning activities. All of these parties opposed the Commission being overly prescriptive about how to use the reference portfolio, even if it is adopted, in their own individual IRPs.

As far as how the reference portfolio should be utilized by LSEs, numerous parties were supportive of LSEs being required to adhere to the portfolio or explain why they are deviating, with most parties also stressing the need for flexibility in meeting individual LSE and customer needs. Parties generally supportive of this approach included AReM, Calpine, CEJA and Sierra Club, CESA, GWT, Reid LSA, NRDC, ORA, SCE, Tesla, UCAN, and Vote Solar.

A few other parties offered conditional support of staff's concept for applying the reference portfolio, with concern for particular issues. SWPG and TransWest supported the staff recommendation, but wanted to ensure out-of-state wind procurement associated with the expiring production tax credits. VEA was concerned about the locational accuracy of the renewable energy zone assumptions in RESOLVE but is otherwise supportive. EDF preferred a more robust set of assumptions associated with DERs before relying on the portfolio mix identified in the RESOLVE analysis.

A large number of parties also disagreed with the staff recommendation, with particular concerns as noted below. AEE preferred that utilities be allowed to propose least-cost, best-fit options for achieving their own specific GHG reduction targets, regardless of sector source (including transportation and industry). Range agreed that LSEs should be given complete flexibility in picking resources and technologies to serve their needs.

CalCCA objected to the idea that the Commission could require CCAs to use the Commission's reference system portfolio, let alone any associated inputs, assumptions, methodologies, scenarios, planning prices, resource mix, or resource timing. CalCCA made various legal arguments about SB 350's applicability. CalCCA also argued that the Commission's resource mix may conflict with some local requirements, citing nuclear prohibitions imposed by some CCA boards or governing bodies. CalCCA also asserted that CCAs are likely to procure more GHG-free resources than the general mix provided by the Commission.

CURE voiced a view at the other end of the spectrum, positing that unless the Commission requires complete adherence to the reference portfolio, LSEs will deviate for any number of reasons. CURE would only support flexibility if the Commission had in place first an ability to ensure that each LSE contributes its fair share to the diverse and balanced system portfolio required by SB 350.

POC objected in general to the whole RESOLVE modeling process and any resulting requirements, calling both flawed. SCE objected to the reference portfolio



dictating procurement of any particular resources, a concern shared by PG&E. SCE preferred a focus on identifying need, required resource characteristics, and the GHG Planning Price, consistent with the Cap-and-Trade program. PG&E offered an alternative approach where the Commission would extract the hourly system level emissions data from the RSP after PCM. Then, utilizing hourly data, each LSE could select alternate portfolios to meet their own resource needs. This would also require a robust load-based GHG accounting mechanism, discussed above.

### **8.3. Discussion**

First, we address what we see as the purpose of the reference system portfolio, as articulated by the September 19, 2017 ALJ Ruling on this topic. The staff analysis using RESOLVE represents our first effort to conduct the electric resource optimization analysis required by Section 454.51(a). We acknowledged in the previous section that there are a number of improvements we would like to make to the next round of analysis. This highlights the importance of the iterative nature of the two-year IRP cycle.

However, the current recommended portfolio, using the RESOLVE analysis, creates a solid foundation to underpin the additional analysis that individual LSEs will undertake in preparing their IRPs.

Responding to several parties' concerns that the lack of ability of the model to optimize DERs at this stage tended to underrepresent DERs in the results, we offer the following revised picture of the total resources, including baseline resources, that are represented in the 2030 reference system portfolio. Figure 3 shows the total portfolio in capacity terms, with Figure 4 depicting the energy basis. Tables 1 and 2 following the figures show the percentage contribution to the total portfolio by each resource type, for capacity and energy.

Figure 3. Total Capacity of Resources in Reference System Portfolio

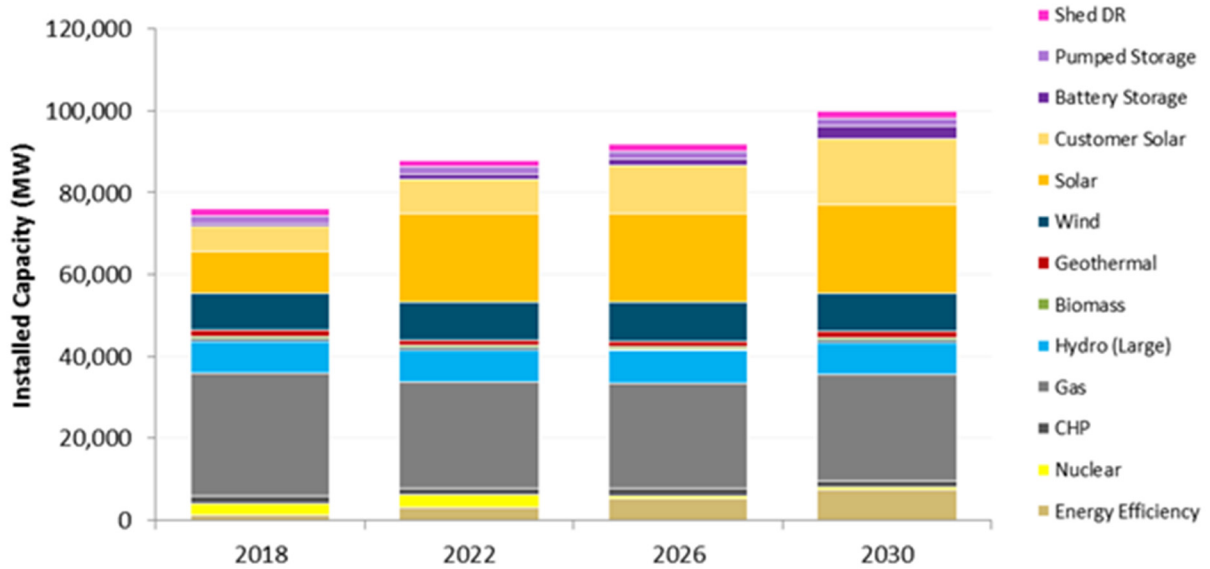
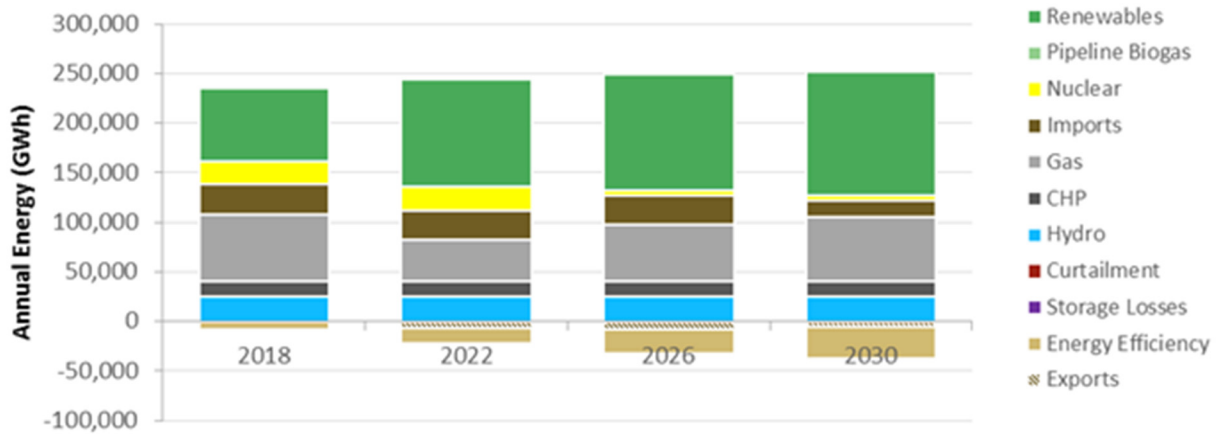


Figure 4. Total Energy Balance in Reference System Portfolio



**Table 1. Proportion of Total Capacity Resources in Reference System Portfolio in 2030**

<b>Resource</b>	<b>MW (% total)</b>
Natural Gas	25.9%
Solar	21.7%
Customer Solar	16.0%
Wind	9.3%
Hydro (Large)	7.9%
Energy Efficiency	7.4%
Battery Storage	3.3%
Pumped Storage	1.8%
Shed Demand Response	1.8%
CHP	1.7%
Geothermal	1.4%
Biomass	0.7%
Nuclear	0.6%
Hydro (Small)	0.5%

**Table 2. Proportion of Gross Energy Generation in Reference System Portfolio in 2030**

<b>Resource</b>	<b>Percentage of Gross GWh</b>
Renewables	44.9%
Gas	23.4%
Energy Efficiency	11.7%
Hydro	9.0%
CHP	5.3%
Net Imports	3.9%
Nuclear	1.8%

\* Gross GWh are defined here as total generation before storage losses and curtailment, net of exports, and adding the energy efficiency back in (treating it as a resource). This does not match Figure 4 exactly, because it does not represent curtailment, storage losses, imports, and exports as individual rows, but represents a more intuitive representation of the proportions.

We agree with the numerous parties that point out that optimization for each LSE's particular load and/or service area may be different than the optimized portfolio

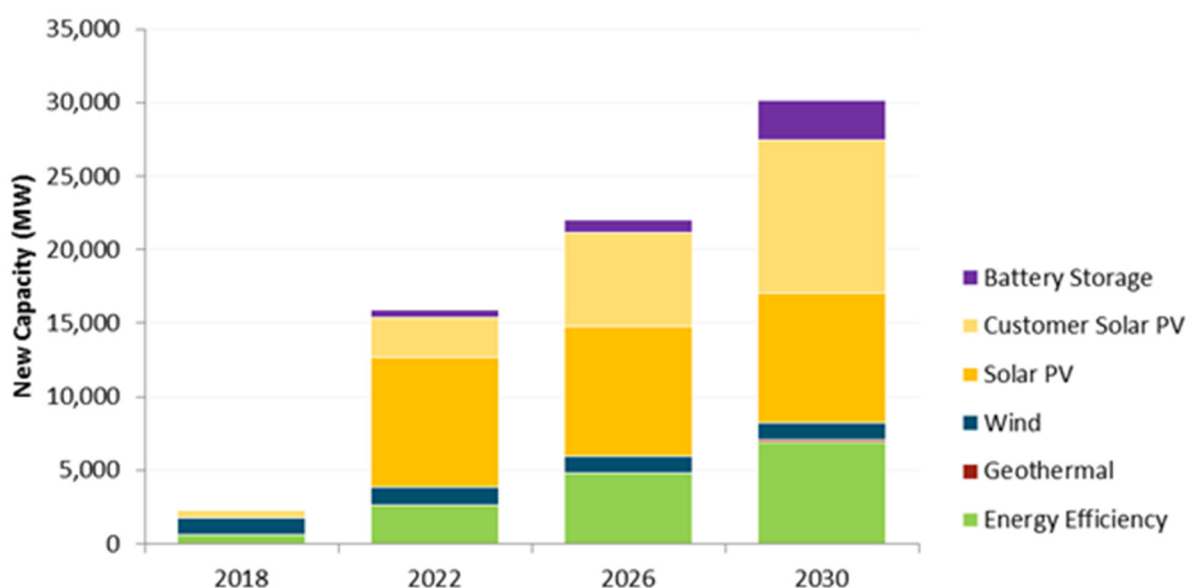
for the entire CAISO system represented by the reference system portfolio. We acknowledge that many LSEs will conduct their own modeling with the benefit of more granular and specific information relevant to their individual needs, and may choose to present alternate portfolios that they would prefer to procure.

Other LSEs may not intend to conduct detailed modeling of their own customer needs and systems, in which case the reference system portfolio provides a convenient guidepost for evaluating a balanced mix of resources that can meet system needs.

Each LSE's planning is likely to start with the determination of whether new resources are needed to serve their load within the planning horizon out to 2030. If a need is identified, the LSE will need to propose procurement strategies to meet that need. This is where the reference portfolio can be helpful.

Figure 5 below depicts the buildout of new resources assumed based on prior requirements and/or selected by the RESOLVE model that make up the reference system portfolio out to 2030. Table 3 includes the proportion of each type of resource making up the total incremental resources in 2030.

**Figure 5. New (Incremental to 2017) Capacity of Resources in Reference System Portfolio**



**Table 3. Proportion of New (Incremental to 2017) Capacity Resources in Reference System Portfolio in 2030**

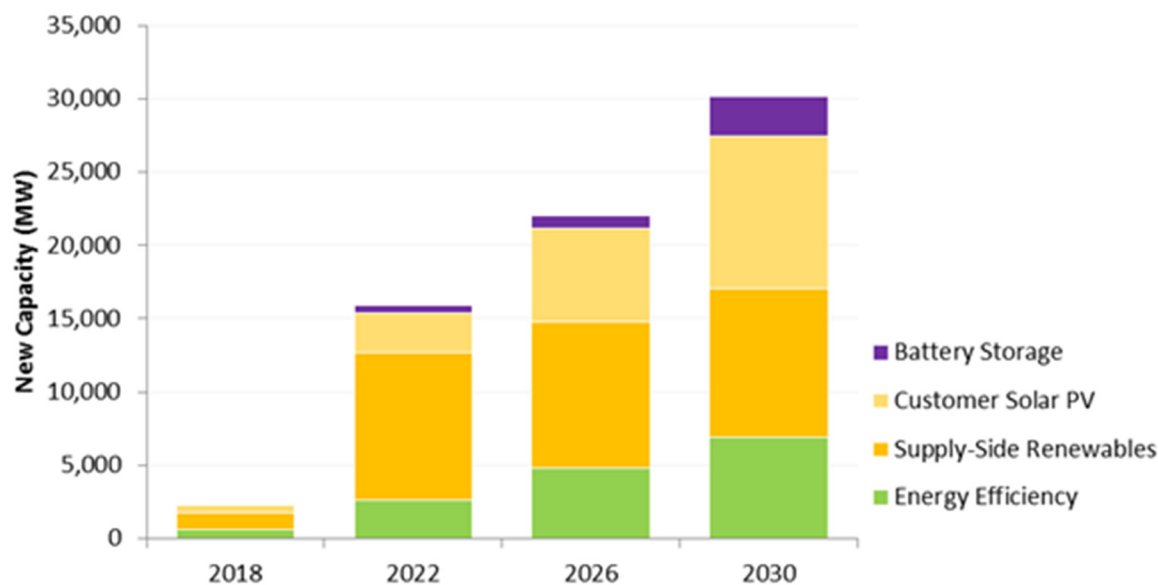
<b>Resource</b>	<b>MW (% total)</b>
Customer Solar	34.3%
Solar	29.3%
Energy Efficiency	22.9%
Battery Storage	9.1%
Wind	3.8%
Geothermal	0.7%

Each LSE may find the above proportions useful, along with the GHG Planning Price and GHG emission benchmark described later in this decision, in developing its conforming portfolio to be presented in its IRP. Each LSE may also present an alternate portfolio, or more than one, justifying why that portfolio is preferable to serve its load.

We also note that LSEs must all meet their existing statutory and/or regulatory obligations for certain types of resources, including renewables, storage, energy efficiency, net metering, and resource adequacy. The RSP does not relieve LSEs of those obligations. Thus, creating an individual LSE IRP is a multivariate equation.

In addition, we acknowledge that while RESOLVE chooses resources that are, in some cases, technology specific, in most cases we procure resources in groups. Thus, for example, while RESOLVE considers solar, wind, biomass, and geothermal resources individually, it is likely that an LSE would plan to procure renewables generally, without specific regard to the exact technology. Thus, in portfolio terms, the incremental resources are more likely to be procured in groups depicted in Figure 6 and Table 4 below.

**Figure 6. New (Incremental to 2017) Capacity of Resource Types in Reference System Portfolio**



**Table 4. Proportion of New (Incremental to 2017) Capacity by Resource Type in Reference System Portfolio in 2030**

Resource	MW (% total)
Customer Solar PV	34.3%
Supply-Side Renewables	33.7%
Energy Efficiency	22.9%
Battery Storage	9.1%

Further, these requirements only apply to each LSE's IRP *plan*. Once *procurement* activities are undertaken, we expect that the LSEs will procure the most effective resources within the groups that meet their cost, reliability, and other needs such as impacts on disadvantaged communities, which may look different from what each LSE's plan proposes.

In sum, the purpose of the reference system portfolio is to point the general direction for planning purposes, for individual LSEs and policymakers, while being

updated with better information at least every two years. Each LSE will be required to plan toward adherence to the reference system portfolio, with specific justification given when its plan deviates from the reference portfolio. When it comes to actual procurement, we expect that LSEs will choose the most appropriate and effective resources offered to them that meet their customers' needs, when analyzing cost, reliability, and disadvantaged communities impacts, among other considerations.

## **9. Consideration of Early Procurement of Renewables to Capture Federal Tax Credits**

One major result of the RESOLVE modeling effort supporting the proposed RSP was that there could be cost savings to California ratepayers by procuring additional renewable energy earlier than required by the RPS, in order to take advantage of expiring federal investment tax credit (ITC) and production tax credit (PTC). Because the model was constrained by the need to meet the GHG emissions targets in 2030, additional renewables beyond the current RPS compliance requirement would be chosen, and the model chose the least-cost solution due to the cost advantages offered by the federal tax credits. Staff analysis suggested that the cost savings associated with capturing the federal tax credits could save approximately \$140 million per year for Commission-jurisdictional LSEs.

### **9.1. Staff Recommendation**

In response to the modeling results, Commission staff offered two possible actions that the Commission could take to potentially reap these benefits for California ratepayers. The first was to raise the RPS compliance requirement for all LSEs, either in the IRP proceeding or the RPS rulemaking. The advantage of this approach would be that the RPS applies to all LSEs by law and therefore it would affect all LSEs proportionally according to their customer needs.

The second possible action suggested by staff would be to order additional renewable procurement in the IRP proceeding, outside of (in addition to) the RPS

compliance context. This would imply additional renewable procurement requirements, perhaps without associated pre-existing RPS compliance requirements.

## **9.2. Comments of Parties**

Parties generally in support of the idea of raising the RPS compliance requirement across the board included AWEA, CEERT, EDF, IEP, National Grid, and Vote Solar. Parties offering qualified support included AEE, Calpine, CalWEA, LSA, NRG, ORA, TURN, and GPI.

Parties opposed to raising the RPS compliance obligation included: AReM, CalCCA, CEJA/Sierra Club, CEDMC, CMUA, Imperial County, NRDC, POC, PG&E, SCE, TransWest, and UCS.

AEE was concerned that raising the RPS would represent a return to siloed procurement, and should only be done after additional DER analysis. However, they supported raising the RPS in an intermediate way, to avoid excessive procurement.

AReM felt that early procurement of additional renewables, of any kind, in the face of declining prices, will increase electricity prices unnecessarily and create additional stranded costs. AReM was especially opposed to conducting renewable procurement outside of the RPS context, because that would likely mean additional cost allocation to ESP customers.

AWEA supported early renewable procurement and pointed out that raising the RPS could force resolution of current market uncertainty around formation of CCAs. They also supported requiring additional procurement of approximately 4000 MW of tax-eligible renewables as a separate track of the IRP proceeding in 2018 and requested that the Commission act on final contracts by the end of 2018. AWEA also suggested that “market power” concerns raised in the workshops and by other parties are not a concern because supply outweighs demand and because there are so many sellers.

BAMx and CCSF suggested that any authorization for accelerated renewables procurement should be deferred, and urged caution about incurring near-term costs for



uncertain future benefits. They are also concerned about increasing transmission congestion and rising curtailment increasing the prices of renewables.

CalCCA characterized the idea of raising the RPS as an “end run” around the legislatively established limits of Commission authority over IRP and CCA procurement activities and did not support the idea of the Commission requiring additional procurement. They argued that SB 350 not require or give the Commission authority to require that CCA programs base their individual IRPs on the procurement timing or resource mix identified by the Commission in its Section 454.51(a) portfolio. Instead, they argued that this is a procurement issue that falls solely within the discretion of each CCA program’s governing board.

CalCCA also pointed out the uncertainty about future renewable costs, including resulting from the International Trade Commission’s investigation of solar import tariffs. They further commented that the Commission should allow banked RECs to count towards achievement of any GHG reduction target. Finally, CalCCA completely opposed the concept that IOUs might be required to engage in procurement on behalf of current or future CCA customers with nonbypassable surcharges imposed to cover the costs.

Calpine was in favor of using the RPS mechanism if additional renewables procurement is authorized because it doesn’t discriminate between resources. Their comments also argued that if these investments are cost-effective, no Commission action should be required since LSEs would naturally want to procure these resources for economic reasons.

CalWEA was concerned that the approximately 58% RPS that would be required identified in the proposed RSP may be too low to meet the GHG requirements and take advantage of all of the available federal tax benefits. Instead, CalWEA suggested that the Commission require each IOU to conduct immediate wind-only procurement for up to 5,000 MW, with a special focus on wind repowers, in order to capture expiring federal PTCs and secure a modest level of portfolio diversity. GWT also suggested that the

Commission order wind procurement in 2017 to take advantage of the federal PTC benefits.

LS Power supported accelerated procurement of out-of-state wind resources for diversity benefits.

CESA stated that the Commission has the authority and should ensure that the state takes advantage of the federal tax benefits before they expire. Defenders agreed, stating that we have done enough scenario analysis and we know that more renewable energy is needed to meet the GHG targets, so we should get on with procuring it.

CEJA and Sierra Club suggested that the RPS program may represent too slow of an approach to capture the federal tax benefits. CESA was similarly concerned about the long RPS timelines.

CEERT urged that additional renewable procurement be initiated in 2018 in the IRP proceeding. They also pointed out that the RPS evaluation methodology does not currently take GHG emissions benefits into account.

CEDMC argued that it is premature to order additional renewable procurement, because of uncertainties and improvements that should be made to the modeling.

CLECA supported ordering additional procurement if there is an identified need, via the IRP, not the RPS. But they argued that additional procurement should not be ordered while the Commission is evaluating whether its policies should change regarding recovery of costs associated with resources procured to serve load that is departing bundled service.

CMUA was concerned that RPS-driven procurement would result in higher ratepayer costs, was not designed to reduce GHGs, and devalues or diminishes REC values, threatening the integrity of the RPS program. Imperial County shared the concern about the RPS program not being designed for GHG reduction, and was concerned that increasing the RPS could favor only some resources in the short term.

EDF pointed out that raising the RPS would help us get out in front of legislative action that may require the same thing. However, they urged caution in requiring any

additional investment in utility-scale renewables, preferring additional DER development to avoid unnecessary or stranded uneconomic investment.

IEP would prefer that the Commission increase the RPS somewhere, either in the IRP, RPS, or the Diablo Canyon closure proceeding. IEP pointed out that time is of the essence on the tax credits, which are already declining rapidly. IEP points out that the Commission need not require procuring all of the necessary renewables by 2030 immediately. A conservative, no-regrets approach would be to order approximately 3,000 MW of procurement.

Imperial County pointed out that geothermal investment can provide many of the diversity and hedging benefits that might be promised by capturing federal tax benefits, since there is uncertainty about the solar import tariff and the Commission should avoid additional overprocurement of solar and wind.

LSA also strongly supported accelerated procurement requirements to take advantage of the expiring tax credits. LSA preferred that changes to the RPS take place in the RPS rulemaking. They were also concerned that raising the RPS may still not result in additional procurement because of the REC banks, a point shared by NRG. Instead, LSA preferred that additional renewable procurement requirements be done in IRP.

National Grid commented that they would like the RPS increased to 60 percent, which they believe would help facilitate electrification and get in front of legislative action.

NRG supported accelerated renewable procurement, but noted that the requirement should incorporate a measure of flexibility, given the uncertainty about CCA development and future allocations of energy and RECs. They also pointed out the need to account for and mitigate the impacts of accelerating renewable procurement by addressing increasing net load.

Reid and ORA would prefer to keep all RPS issues within the RPS proceeding and not have the Commission address early procurement of renewables in the IRP context.

Reid also argued that the Commission should not assume that the ITC will be eliminated in 2018.

Ormat suggested that the energy and capacity value of additional solar resources will be decreasing and become significantly lower than the value of other renewables including geothermal. Thus, the Commission should not require more solar investment.

PG&E, SCE, and SDG&E all opposed any potential requirements for early procurement of renewables beyond RPS need. SCE pointed out that a good price assisted by federal tax credits does not in itself justify renewable purchases. PG&E argued it is contrary to the ideals of an IRP process, would create a duplicative requirement, and force near-term procurement on LSEs who do not have a procurement need, thereby increasing customer costs. PG&E also voiced concerns about speculative future market prices of renewables. PG&E commented that if the Commission did decide to order early procurement, it should be done through RPS instead of IRP. SCE felt that the cost savings modeled in RESOLVE are unlikely to be realized.

POC agreed that there is no near-term need for additional renewable energy in IOU portfolios in the near future, and therefore early procurement requirements should not be imposed. They argued that the ITC and PTC should not drive procurement.

SEIA commented that accelerated renewable procurement should be ordered, and provided an illustrative schedule for decision-making and procurement. Their comments suggested a focus on timely procurement, rather than further analysis to try to determine the exact optimal amount.

VEA, Tesla, and Vote Solar also supported early procurement to capture ITC and PTC benefits, and were fine with it being done outside of the RPS context. Vote Solar preferred a special IRP/GHG procurement cycle rather than wait for the next iteration of RPS, and also pointed out the advantages of procuring early to replace Diablo Canyon output. SWPG also strongly supported early procurement requirements.

TransCanyon's comments were focused on procurement activities to facilitate price discovery, especially of out-of-state-wind resources to feed into the CAISO's TPP process.

TransWest argued that uncertainty over load migration should not stand in the way of taking advantage of federal tax credits for the benefit of consumers.

UCS supported requiring early renewables procurement because the modeling analysis shows that renewables in excess of current RPS requirements will be needed by 2030 to meet GHG targets. In addition, UCS pointed out PG&E's public commitments to replace Diablo Canyon output with GHG-free resources, so PG&E will need additional renewables.

UCAN's comments focused on first determining the need for new resources before evaluating the potential incremental costs and benefits.

### **9.3. Discussion**

Despite the potential for cost savings for ratepayers identified by Commission staff in their optimal portfolio analysis using RESOLVE, we are not persuaded of the need to order near-term procurement of additional renewables at this point in time. There are numerous reasons that we decline to order additional renewables procurement, outside of the RPS requirements, now.

Most importantly, the cost savings estimated by Commission staff that could flow from capturing the federal tax credits are highly uncertain. ITC and PTC eligibility rules have different timing requirements, declining benefits, and expiration dates. It is also a possibility, though remote, that the federal tax credits may be extended.

In addition, solar tariff actions may result in an increase in costs, rather than capturing a benefit, if procurement was required. Further, renewable costs have been declining for many years, and likely will continue to do so, regardless of federal tax benefits. Buying additional resources now may lock in higher-than-necessary prices than those that would otherwise occur if renewables were procured commensurate with load growth and portfolio need. Renewable cost forecasts published by Bloomberg New

Energy Finance also suggest that for solar PV, improving operational efficiencies may also mitigate against price increases even in the absence of tax benefits.

Next, staff conducted a sensitivity case that removed all federal tax credits, and only a minor amount (approximately 250 MW) less renewable capacity was procured than otherwise would have been selected.

Further, although federal tax credits may be available to developers in the near-term, there is no guarantee that all of those benefits will flow through to ratepayers in the form of lower prices, especially if the Commission creates an artificial scarcity by requiring a set amount of early renewable procurement outside of reliability, RPS, or GHG-related need.

In addition, there is no “need” on a reliability basis or for the GHG emissions reductions required from renewables until around 2026, according to the modeling analysis. Procuring the renewables in a more orderly fashion in the course of the next decade or so will still result in our ability to meet our 2030 GHG targets.

Declining to order additional early procurement of renewables also allows us to avoid a number of other problematic issues that would be associated with implementing such a requirement. The prospect of a large amount of departing CCA load in the next decade creates a conundrum for renewable procurement, even in the context of RPS, let alone new IRP requirements. The IOUs have made substantial RPS investments and may not need to engage in a great deal of RPS procurement in the near term, especially while facing the prospect of a large amount of departing load.

Thus, the largest “need” for renewables will exist for the CCAs that have yet to be launched, since they will then face an immediate RPS obligation under the law. But such entities not yet serving load are not positioned to be able to take advantage of immediate federal tax credit opportunities by purchasing electricity for customers that they do not yet serve.

Therefore, if we ordered immediate additional renewable procurement, we would be forced, at least to some degree, to rely on IOUs to undertake procurement that they

may not need by 2030 to serve their bundled load, and then devise a likely-unpopular cost allocation methodology to ensure that the costs are shared by the benefitting customers.

We conclude that to address this situation, our efforts are better spent examining opportunities to ensure greater flexibility in the RPS compliance market. If LSEs are able to acquire renewables to serve their customers, and then later sell that renewable energy at a market rate to an entity that may be serving those same customers in the future, that would represent a more efficient market outcome than grafting additional cost responsibilities onto an already complex RPS (or new IRP renewables procurement) compliance regime.

## **10. Portfolios for use in CAISO TPP**

This section discusses the appropriate portfolios to be used by the CAISO in its 2018-19 TPP, as well as the manner in which portfolios will be transmitted by the Commission to the TPP process, in coordination with the CEC, in the future.

### **10.1. Staff Proposal**

The September 19, 2017 ALJ Ruling containing the proposed RSP suggested that the Default Scenario be transmitted as the Reliability Base Case for the 2018-19 TPP, with the 42 MMT Scenario utilized as the policy-driven portfolio under the CAISO TPP tariff and the terms of the process alignment agreement between the CAISO, CEC, and this Commission.

### **10.2. Comments of Parties**

AWEA supports use of the Default Scenario as the reliability base case, since it represents an appropriate minimum buildout for reliability. BAMx agrees and cautions against approving reliability projects based on an assumption about early procurement. Calpine, Reid, CEJA/Sierra Club, TransCanyon, and TransWest all agree. CESA agrees, but would prefer adding the low-battery cost sensitivity, and TNC agrees if 6 GW of solar is added to the Westlands competitive renewable energy zone.

Several parties oppose the use of the Default Scenario as the reliability base case, instead preferring that the 42 MMT Scenario be used for reliability, since it represents a

more likely future and would support the identification and development of more transmission to support the portfolio earlier. These parties include CalWEA, GWT, ORA, SEIA, and POC. Ormat agrees, but prefers lower geothermal cost estimates.

Several other parties oppose the use of the Default Scenario for various reasons. AEE opposes because it does not include enough out-of-state resources. CalCCA does not support transmittal of any portfolios until the cost allocation issues are resolved in the PSP. GPI and SDG&E oppose because the portfolio includes too much in-state solar PV, which lacks diversity and will worsen grid integration issues. NRG opposes because of its concern about the gas resource assumptions. PG&E and LS Power oppose because any portfolio used in the TPP should be based on the aggregation of the individual LSE plans, the PSP. SVLG feels that the Default Scenario does not include enough of a market signal to encourage additional DER development.

SWPG opposes the use of the Default Scenario in the TPP because the TPP should be based on actual procurement, not planning assumptions. Finally, VEA is concerned that the Default Scenario is suboptimal because VEA generation is not represented in the RSP.

SCE is neutral on the Default Scenario, and defers to the CAISO, with concerns that there may not be enough geographic specificity for the CAISO to rely on for TPP purposes.

With respect to the use of the 42 MMT Scenario as the policy-driven scenario for TPP purposes, numerous parties support this proposal, including CalWEA, Calpine, CEERT, CESA, GWT, Imperial County, Reid, ORA, POC, SEIA, SVLG, TransCanyon, and TransWest, though some prefer changes to some of the underlying assumptions for particular resources.

Some other parties state specific reasons for opposing the use of the 42 MMT Scenario as the policy-driven portfolio. AEE opposes because there are not enough out-of-state resources contained in the portfolio, a concern shared by Pattern. BAMx feels that the PSP should be the portfolio for transmission development purposes. CEJA and



Sierra Club would prefer the 30 MMT Scenario. LS Power suggests sending two portfolios, including the 42 MMT Scenario, as well as one driven by LSE inputs. PG&E states that the 42 MMT Scenario should only be used for study, not transmission development. SDG&E feels the scenario is too aggressive overall, and Vote Solar is concerned that there is a lack of granularity to the needed ramping capacity in RESOLVE, and therefore this case should not be relied upon.

A number of parties also commented on the appropriateness of the use of the RETI 2.0 work to inform the TPP.

Numerous parties supported the use of the RETI analysis. The following parties generally commented that all of the best available information should be utilized, including the RETI analysis: CESA, LSA, Pattern, SWPG, TransCanyon, and TransWest. AEE supported study of the RETI lines and the National Renewable Energy Laboratory's Low Carbon Grid Study for potential transmission development in the 2018-19 TPP. AWEA recommended that the RETI analysis be used in future TPPs. The CAISO and CalWEA would prefer that the RETI analysis inform the RESOLVE modeling, and not the TPP directly.

Imperial County specifically cited a 523 MW assumption of existing capacity available from IID into the CAISO for geothermal resources that it recommended should be used.

LS Power recommended a follow-up study to analyze the impacts of coal plant retirements, which could potentially open up transmission capacity on existing lines for new resources. National Grid specifically pointed to the importance of the RETI analysis related to the California Oregon Intertie. ORA also supported use of RETI's analysis, and recommended that a Bureau of Ocean Energy Management report should be used in future IRP cycles.

Several parties were also opposed, or had significant concerns, about the use of the RETI 2.0 analysis in RESOLVE modeling and in the TPP. CMUA and PG&E commented that the RETI analysis should not be given undue weight because it has not

been vetted in a litigated proceeding. Defenders felt that the RESOLVE environmental data is reliable and RETI does not augment it. Finally, SCE recommended that this TPP should focus on better utilization of existing capacity, with a focus on in-state renewables for this round.

### **10.3. Discussion**

Since the Default Scenario represents the business-as-usual scenario that is reasonably likely to occur based on existing policy, we agree with staff that this is the appropriate one to utilize for the reliability base case for the CAISO's TPP.

Since we are adopting the 42 MMT Scenario as the planning target for individual LSEs planning their IRPs, we also agree this is the appropriate target for use as the policy-driven scenario in the TPP.

We recognize that both scenarios, to some degree, represent a less granular geographic data set than is required for CAISO to conduct transmission planning studies. We delegate to Commission staff to work with the CEC and the CAISO, as part of its stakeholder process, to develop the required granularity. This collaborative approach is consistent with our previous practices of providing data informing CAISO transmission planning. Staff should begin by utilizing the RETI 2.0 work to the extent possible, to identify the best-available project and geographic information for use in both scenarios, working with the CEC and CAISO staff.

## **11. GHG Planning Price – Calculation and Use**

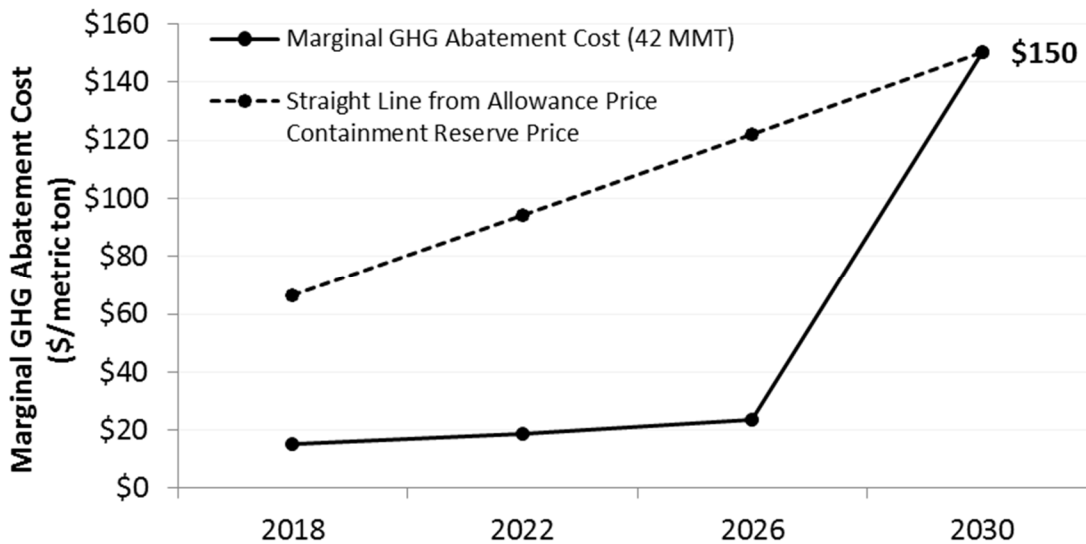
This section discusses the proposed GHG Planning Price articulated by staff in both the May 2017 IRP Staff Proposal and the proposed RSP, designed to approximate the marginal cost of GHG abatement associated with the chosen GHG target and resulting resource portfolio.

### **11.1. Staff Proposal**

As part of the proposed RSP, Commission staff used the RESOLVE modeling output to calculate the marginal cost of GHG abatement associated with the 42 MMT Scenario in 2030. Figure 7 below shows the results, along with the staff recommendation

to use a straight line interpolation between the current Cap-and-Trade Allowance Price Containment Reserve amount to the GHG abatement cost in 2030 of \$150 per metric ton.

**Figure 7. Proposed RSP GHG Planning Price**



Commission staff in the proposed RSP suggested that the individual LSEs use the GHG Planning Price, recommended as the dotted line in Figure 7 above, as a constraint in their individual IRP submittals. If the GHG Planning Price is used as an input in the IRP process, as the marginal GHG abatement cost, each LSE should be able to identify a resulting portfolio with an estimated GHG emissions profile for its individual customer base and portfolio of owned or contracted resources.

In developing its portfolio, each LSE would add resources that reduce GHG emissions up to the point that the marginal cost of doing so equals the GHG Planning Price. One approach was for LSEs to use the GHG Planning Price in lieu of the Cap-and-Trade allowance cost in calculating the marginal cost of GHG-emitting resources. Then, if the LSE added a resource that lowers the total portfolio cost (including cost of capital, fuel, etc.), the resource would be considered justified. LSEs would continue adding resources until the cost of adding resources outweighs the benefits, or the total cost prevents the LSE from serving its customers reliably and at just and reasonable rates.

In addition, staff acknowledged that LSEs may also be motivated by factors other than cost. For example, to the extent that LSEs' future resource procurement plans reflect environmental, risk, and other factors not directly related to minimizing marginal costs, the LSE would describe its rationale in detail, with reference to all applicable state or local statutory requirements.

Essentially, staff suggested that each LSE should be willing to propose to buy any low- or zero-GHG resource at a marginal cost that is less than the GHG Planning Price, and should describe the portfolio that would result from utilizing that assumption. Each LSE should also explain the relationship between that ideal portfolio, its existing portfolio, and any new resources required to be procured to make up any difference.

After validation and approval by the Commission as part of the development of the PSP, this GHG emissions estimate associated with the LSE's proposed portfolio would become the LSE-specific GHG target for the individual LSE for the subsequent planning cycle.

Staff recommended that each LSE have two options for estimating the annual GHG emissions associated with its portfolio:

1. The LSE may quantify direct and indirect GHG emissions for forecast years using methods consistent with the Energy Resource Recovery Account (ERRA) applications, specifically as instructed in Lines 1 through 12 in Template D-2 in Attachment D of D.15-01-024. That decision provides guidance on how to quantify emissions from different energy sources, including from utility-owned generation, unspecified energy imports, and contract and market purchases. The total emissions calculated for each LSE would be made publicly available.
2. Alternatively, if the LSE conducts capacity expansion or production simulation modeling over the IRP planning horizon, the LSE will be able to determine the resource composition of its portfolio, the ability of the resources in its portfolio to serve its own load in consideration of that load's underlying shape, and therefore its total fuel consumption or total market purchases. In that case the LSE would apply standard fuel emissions factors for estimating GHG emissions associated with those

resources or market purchases. For estimating GHG emissions from unspecified imports, the LSE would use CARB's default emissions factor utilized in its cap and trade regulation.<sup>16</sup> For estimating GHG emissions from in-CAISO unspecified power, LSEs would use the GHG emissions factor associated with the portfolio selected for the Reference System Plan.

Under the staff proposal, LSEs would indicate which new resources they anticipate procuring with reference to the four planning years modeled (2018, 2022, 2026, and 2030). For estimating the GHG Planning Price across these years, Commission staff proposed to project a straight-line increase beginning at the 2018 Cap-and-Trade Allowance Price Containment Reserve value (consistent with D.17-08-022) and increasing to the level of the 2030 GHG Planning Price of \$150 per metric ton. This approach avoided having a relatively low GHG Planning Price value from 2018 to 2026 followed by a steep increase during the final few years of the planning horizon, which would increase the risk that cost-effective GHG-free investments are not realized by 2030.

The September 19, 2017 ALJ ruling also noted that the purpose of the GHG targets, both for the sector as well as for individual LSEs, is for planning only. The Commission is not contemplating requiring after-the-fact compliance with the targets used for up-front planning. Compliance is intended still to be measured with respect to the individual programs which will support attainment of the GHG goal, including the RPS, storage mandate, energy efficiency goals, etc. In addition, the ruling stated that ultimately the Cap-and-Trade program would be the compliance mechanism for the state for GHG emissions compliance purposes.

The proposed RSP recommended by Commission staff also included the recommendation to utilize the GHG Planning Price as a replacement to the GHG adder recently adopted in D.17-08-022 in the integrated DER (IDER) proceeding. Staff

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<sup>16</sup> CARB's current figure is 0.428 MT of CO<sub>2</sub>e per megawatt hour (MWh) or 943 lbs per MWh, but this figure may be updated in the future.

suggested that the most straightforward manner in which the GHG Planning Price could be used as an avoided cost input is to project a straight line increase in the GHG adder beginning at the 2018 level adopted on an interim basis in D.17-08-022 and increasing to the level of the 2030 GHG Planning Price suggested by the chosen GHG Scenario in the IRP proceeding.

### **11.2. Comments of Parties**

Several parties fully supported the staff recommendation of using a straight-line projection from the 2018 Allowance Price Containment Reserve level to the 2030 GHG abatement cost estimated by RESOLVE of \$150 per metric ton of CO<sub>2</sub>e. Those parties include AEE, CEJA and Sierra Club, CESA, Imperial County, Reid, LSA, NRDC, and UCS.

CEJA and Sierra Club supported the straight-line approach if it is used in conjunction with individual LSE GHG emissions benchmarks. They also supported the straight-line approach because it would avoid procuring most resources at the end of the planning period and is consistent with what was adopted in the IDER proceeding recently.

CESA supported the proposal because it would better align individual IRPs to a common set of assumptions and would allow for some consistency in the IRPs.

Imperial County commented that the proposal represents a reasonable alternative to transition from the current GHG adder in the IDER proceeding, while also providing LSEs flexibility to procure resources based on factors other than costs.

Some other parties supported the recommendation to use a GHG Planning Price, but disagreed with the proposed straight line values. Calpine supported prices that are no higher than projections of Cap-and-Trade allowance prices.

ORA supported the general approach of a straight line, but recommended that the starting price be based on December 2017 Cap-and-Trade futures on the Intercontinental Exchange index. ORA also recommended that the Commission examine the potentially

unexpected effects of a significantly higher GHG Planning Price, since the impact of carbon costs may not be linear.

PG&E generally supported the concept of allowing LSEs to use a set of GHG prices for planning, but would prefer the figures be in line with the Cap-and-Trade price. In addition, PG&E characterized the \$150 per metric ton in 2030 figure as “wholly inappropriate” because it disproportionately burdens the electric sector, could depress the market price for allowances by suppressing demand, and will create barriers to cost-effective fuel-switching. PG&E conducted its own RESOLVE modeling and recommended a 46 MMT Scenario that yields a 2030 GHG Planning Price of \$88, which is more in line with the Cap-and-Trade ceiling price and results in approximately a 54 percent RPS.

SDG&E’s comments generally tracked those of PG&E, and added that the straight line projection, rather than following the actual RESOLVE results, would result in unnecessary costs to customers.

SoCalGas would like the GHG planning Price to be completely consistent with Cap-and-Trade allowance prices.

Vote Solar support using a common GHG Planning Price, but does not suggest it be based on RESOLVE outputs because of concerns about inadequate representation of reliability-based resources and DERs. Vote Solar’s comments did support the straight-line nature of the recommendation, arguing that it provides for hedging benefits to support more early procurement of clean, GHG-reducing resources.

Numerous other parties disagreed with the staff recommendation. AReM commented that the GHG Planning price is more appropriate for LSEs using sophisticated computer models to develop their IRPs. AReM represented that ESPs have smaller customer bases and fairly stable load forecasts, so will likely find it simpler to use the GHG emissions benchmark (discussed further in Section 12 of this decision) instead.

BAMx and CCSF were concerned that the straight-line approach unnecessarily raises costs of achieving GHG reductions and undermines the Cap-and-Trade program.

CAISO pointed out that using the GHG Planning Price as an input cost co-efficient of GHG emissions may not produce the GHG emissions and resource additions that match the RSP portfolio. They referred to PG&E's case run using the \$150 per metric ton abatement cost, with a resulting 43 MMT of GHG emissions at a significantly higher system cost and higher renewable build. CAISO instead recommended instead assigning an emissions allowance in MMT to each LSE and enforcing it as a constraint.

CalCCA objected to the GHG Planning Price requirement on legal grounds, arguing that it is inconsistent with Sections 454.52(b)(3) and (a)(1)(A). CalCCA argued that each CCA program's governing board is responsible for determining whether its program's IRP achieves results consistent with the GHG reduction targets set by CARB in consultation with the Commission and the CEC; the proposed GHG Planning Price has not been approved by CARB.

CalCCA suggested that the GHG Planning Price be treated as a useful, but advisory, tool for LSEs that can help them achieve compliance with the targets established by CARB. They also argued, similar to other LSEs, that the GHG Planning Prices are too high relative to the actual and projected allowance prices, which will increase costs to consumers and cause the electric sector to over-pay for GHG reductions.

SCE would prefer that the Commission set mass-based targets for each LSE, or at least allow LSEs to utilize either the GHG Planning Price or the mass-based GHG benchmarks, in their IRPs. SCE argued that mass-based targets are consistent with CARB's Cap-and-Trade approach, as well as the CEC's treatment of POUs. Mass-based targets, according to SCE, would ensure that once aggregated LSE plans are aggregated, they will be aligned with the overall sector target. SCE was also very concerned about creating disincentives for fuel-switching.

UCAN argued that requiring each LSE to use the GHG Planning Price independently may be suboptimal when aggregated; UCAN would prefer that GHG



reduction responsibilities be shifted to LSEs with the lowest procurement and/or GHG abatement costs.

Additional parties expressed specific concerns about the recommendations. Tesla was concerned about accounting for co-benefits of both GHG reductions and other energy benefits or ratepayer cost savings.

TURN included a number of detailed comments that generally expressed concern that the recommended approach may result in LSE IRPs that do not actually lead to development of new clean resources and do not reflect the real-world impacts of procurement. First, TURN suggested that the use of standard emissions factors and default emissions factors for imports are inadequate. TURN was concerned that resource shuffling is likely to occur. For example, while CARB has determined that tradeable RECs are not a GHG compliance instrument, CCAs and ESPs may seek to treat unbundled RECs as GHG-free resources. In addition, TURN argued that many LSEs, CCAs in particular, treat purchase of “firmed and shaped” renewable energy from out-of-state intermittent generators as zero GHG, but sometimes those generators could also separately sell their null power into California as a zero-GHG product under Cap-and-Trade rules.

TURN also commented on the flaws in the use of the default emissions factor for unspecified imports. In particular, TURN pointed out that the average factor masks underlying resource mixes that can vary significantly depending on geographic origin. TURN also criticized the application of the factor in every hour of the year, without regard to different operating hours or seasons. As an alternative, TURN recommended that the Commission calculate, as suggested by staff, the GHG emissions factor associated with the portfolio selection for the RSP, and then provide parties an opportunity to comment on the methodology.

Numerous parties also commented specifically on the proposal to use the GHG Planning Price as the replacement to the GHG adder in the IDER cost-effectiveness analyses. Parties generally supporting this concept were AEE, CEDMC, CEERT,

CEJA/Sierra Club, Imperial County, NRDC, POC, SEIA, Tesla, UCS, and Vote Solar. Tesla also commented that the Commission will need to clarify what GHG Planning Price values should be used beyond 2030, since the IDER planning horizon is longer than the IRP one.

PG&E and SCE commented that the GHG Planning Price should not be used in IDER cost-effectiveness analysis until DERs are optimized in IRP in the next cycle. PG&E was concerned that the price was too high and would result in procuring DERs that are not cost-effective. SCE argued that it was inherently inconsistent to produce the RESOLVE “hockey stick” output but then suggest the straight-line price to IDER.

Finally, PG&E spent a great deal of time in its comments raising concerns about the proposal to use the ERRA accounting method to determine individual LSE emissions for IRP purposes. PG&E also discussed an approach that they presented to the CEC related to the CEC’s responsibilities under AB 1110 for Power Source Disclosure purposes.

### **11.3. Discussion**

We are sensitive to the parties’ comments pointing out that use of GHG Planning Prices that are significantly different than actual or projected Cap--and-Trade allowance prices could result in suboptimal outcomes for the electric sector. However, we emphasize that our staff’s recommendations are for *planning* purposes only; we are not setting a market price.

We agree with prior statements by staff and the ALJ in rulings in this proceeding that the IRP process is not designed to create an additional GHG *compliance* regime. Rather, we are using this IRP process to identify opportunities and plan for future conditions with some degree of insurance, to increase the chances that we can actually achieve the GHG targets at the least cost to electric ratepayers. As such, there is inherent value in planning for at least slightly more aggressive targets than may be required, and assuming slightly higher prices than may actually come to pass. We also emphasize that the purpose of this exercise is not to require actual *procurement* of resources that cost as

much as the GHG Planning Price assumptions. The actual procurement costs will be discovered at the time that procurement is conducted, and may or may not match the assumptions we utilize today.

Having said all of that, we still see value in utilizing a common set of assumptions for planning purposes, for all LSEs, to ensure comparability and consistency. As stated earlier in this decision, LSEs will be permitted to deviate from our standard assumptions with justification.

We agree with SCE's suggestion that each LSE be given the option to plan utilizing a GHG Planning Price (for LSEs conducting more detailed modeling and planning) or a GHG benchmark (discussed further in Section 12 of this decision).

For LSEs utilizing the GHG Planning Price, which must include all LSEs filing Standard IRPs as further defined in Section 13 of this decision, we modify the staff recommendation, and instead require that these LSEs utilize the actual RESOLVE output of the GHG abatement prices, rather than the straight-line methodology originally suggested by staff. This method still requires some interpolation of RESOLVE results, because the model was only run for four intervening years between now and 2030. This change results in GHG Planning Prices for use in IRP given in Table 5 below.

**Table 5. GHG Planning Prices for Use in IRP**

<b>Year</b>	<b>Price per metric ton of CO<sub>2</sub>e emissions</b>
2018	\$15.17
2019	\$16.05
2020	\$16.94
2021	\$17.88
2022	\$18.86
2023	\$19.91
2024	\$21.02
2025	\$22.19
2026	\$23.44
2027	\$55.08
2028	\$86.72
2029	\$118.36
2030	\$150.00

As with other aspects of the RSP, we will re-evaluate these assumptions in each IRP cycle and update them, based on the extent to which expected GHG emissions reductions are being realized or surpassed in all sectors of the economy.

We also intend to utilize the GHG emissions information reported in each LSE's IRP, once approved by the Commission, as the basis for a mass-based GHG planning target for that LSE in the next IRP cycle, allowing for necessary adjustments due to load-shifting. We will work closely with CARB in conducting this analysis and setting these targets based on the requirements in SB 350.

We have already been working closely with CARB on this recommendation, and believe that CARB will be initiating activities to align with our suggested approach, along with the CEC's approach for POUs. Thus, CalCCA's concerns about CARB's role should be alleviated by the next IRP cycle. In the meantime, we do not agree with CalCCA's analysis that only their governing boards may assess their IRPs against the GHG targets. Sections 454.51 and 454.52 clearly give the Commission authority over the planning process, of which this is one aspect.

We are also mindful of the potential impacts of these assumptions on incentives for electrification. We expect this issue to be a significant focus of our efforts in the next IRP cycle.

We also take a different approach to use of the GHG Planning Price in the context of IDER cost-effectiveness analysis. For purposes of IDER, we will use the original staff recommendation of a straight-line set of assumptions using the adopted GHG adder in D.17-08-022. The GHG Planning Price described above will be utilized for overall IRP planning purposes, but we will also require a GHG Adder to replace the one adopted in D.17-08-022, that is calculated based on RESOLVE outputs.

Table 6 below gives the GHG adder values produced by the RESOLVE IRP RSP analysis now made available for use in the IDER proceeding, and any other proceedings that rely on assumptions about the GHG benefits of DERs.

**Table 6. GHG Adder based on RESOLVE results for use in demand-side cost-effectiveness analyses**

<b>Year</b>	<b>Price per metric ton of CO2e emissions</b>
2018	\$66.37
2019	\$73.34
2020	\$80.31
2021	\$87.28
2022	\$94.25
2023	\$101.22
2024	\$108.19
2025	\$115.15
2026	\$122.12
2027	\$129.09
2028	\$136.06
2029	\$143.03
2030	\$150.00

This approach represents a compromise designed to give market and timing certainty to DER providers, while being linked to IRP analysis. DER resources depend, more so than other resource options, on a smooth trajectory of values and assumptions, and longer planning horizons. Mobilizing millions of individual actions in the DER space is inherently more difficult, all other things being equal, than conducting supply solicitations. Thus, we see value in maintaining a higher and smoother curve for a GHG adder to be used in DER cost-effectiveness analyses.

In the short term, it is likely that these assumptions will impact the next round of analysis of energy efficiency goals and potential. Demand response may also re-evaluate its budgets for 2020 and beyond. As with other aspects of the IRP planning process, we will revisit these assumptions in the next round of IRP, and we expect that over time it is likely that the DER GHG adder and the IRP GHG Planning Price will converge.

On the issue of the accounting for the GHG emissions from the portfolios of each LSE, we elect to utilize the suggestions of PG&E to the CEC with respect to the Power Source Disclosure requirements, and characterized in their comments as the “clean net short” method, specifically for apportioning the GHG emissions associated with the

system's dispatchable fossil generation to each LSE based on how it relies on unspecified power from the CAISO system. The details of this accounting method are spelled out in Attachment A to this decision, but in short, they include the following steps:

1. Each LSE subtracts any owned or contracted non-dispatchable GHG-emitting resources (such as CHP or fossil imports) from its projected hourly electricity demand.
2. Each LSE then further subtracts its owned or contracted (current or planned) GHG-free generation from the projected hourly electricity demand, deriving a "clean net short" value.
3. The clean net short value is then multiplied by the system emissions on an hourly basis, yielding total emissions associated with using unspecified system power for that LSE for every hour of 2030.
4. Finally, the emissions from all owned or contracted non-dispatchable GHG-emitting resources used to serve hourly load in step 1 above will be computed using plant-specific emissions factors and added to the emissions from unspecified system power calculated in step 3 above.

LSEs will have two options for sourcing the hourly system emissions values used in Step 3 above when estimating the GHG emissions of their portfolios: production cost simulation or standard values based on RESOLVE outputs from the RSP. Commission staff will make available the latter values in early 2018 for use in individual LSE Plans.<sup>17</sup>

## **12. LSE-Specific GHG Emissions Benchmarks**

This section discusses an alternative to use of the GHG Planning Price to back into LSE-specific GHG emissions targets by 2030, which is based on calculation of an LSE-specific target utilizing the draft CARB allowance allocation methodology for Cap-and-Trade allowances.

### **12.1. Staff Proposal**

In the proposed RSP, Commission staff acknowledged that while providing the Reference System Portfolio and GHG Planning Price as general guidelines affords LSEs flexibility in developing their own preferred portfolios, LSEs may also benefit from

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<sup>17</sup> This information will be posted at: <http://www.cpuc.ca.gov/irp/filingtemplates/>.

having more specific criteria by which they can assess the reasonableness of their GHG estimates prior to the filing of their plans. For this reason, staff proposed that each LSE compare the emissions associated with its preferred portfolio against a Commission-assigned GHG Emissions Benchmark.

This benchmark was designed to serve as a reference point by which both the LSE and the Commission could cross-check the LSE's use of the GHG Planning Price. As with the GHG Planning Price, this was not intended as a compliance requirement and no enforcement was contemplated or suggested.

Under staff's proposal, if the total emissions attributable to the LSE's preferred portfolio exceed its GHG Emissions Benchmark for 2030, the LSE would be required to explain the difference and describe additional measures it would take over the following 1-3 years to close the gap, along with the cost of those measures. If the gap was significant, the Commission could require the LSE to modify its plan.

The GHG Emissions Benchmark was proposed to be calculated in two steps. First, Commission staff would divide the 2030 GHG planning target for the electric sector among Commission-jurisdictional electric distribution utilities (EDUs) based on CARB's draft methodology for the 2021-2030 allowance allocation under the Cap-and-Trade program, similar to the how the electric sector target is divided between the Commission's and the CEC's respective IRP processes.

Next, staff would further divide that value proportionally among the host EDU and non-EDUs (CCAs and ESPs) within the host EDU's territory based on their projected 2030 load shares. The resulting value would become the LSE's assigned GHG Benchmark for IRP planning purposes.

Because ESP load forecast information (consistent with IEPR Confidential Form 7.1) is considered confidential, the GHG Emissions Benchmark would be determined for all ESPs in aggregate within each IOU service territory, and these top-level values would be made public. However, each ESP would be required to calculate its own confidential

GHG Emissions Benchmark using the formula outlined above, and to use that benchmark in developing its individual IRP.

### **12.2. Comments of Parties**

Many parties supported the GHG emissions benchmark proposed by staff, either instead of or in addition to the GHG Planning Price. Generally supportive parties included AEE, CEERT, CESA, EDF, NRDC, ORA, SCE, Tesla, UCAN, and UCS. Vote Solar also agreed, and stated that the CCAs need flexibility but also need to be held accountable for their share of GHG emissions. Reid recommended that the Commission require ESPs to publicly file their GHG emissions benchmark.

AReM supported the GHG benchmark proposal, but requested that the Commission provide a single benchmark for each ESP, even if the ESP serves in multiple IOU service territories. AReM proposed two methods for calculating the benchmark: based on the LSE's projected 2030 load or as proposed by staff, but then adding the separate IOU-specific benchmarks for each ESP to result in one benchmark. AReM also requested that the Commission clarify that review of the ESPs' IRPs will be on a statewide basis, and that ESPs will not be subject to requirements for separate review by IOU territory.

SCE preferred that the GHG emissions benchmark be the primary measure of an LSE's contribution to the statewide GHG target, rather than the GHG Planning Price, stating that the method is simple and fair.

CEJA and Sierra Club commented that the benchmark is transparent and helps ensure that the aggregated LSE plans will meet the sectoral GHG emissions limit set by CARB. Without the benchmark, they felt that an individual LSE would not know whether its efforts were sufficient until after the PSP was adopted by the Commission.

Some parties were somewhat indifferent to the benchmark proposal, including NRG, which urged caution with regard to assigning benchmarks, because such metrics are too simplistic, and Imperial County, which felt that there was insufficient information



at this time and that associated air pollution impacts for disadvantaged communities should also be somehow considered.

Other parties disagreed with the benchmark proposal. CalCCA stated that a better approach would be to focus on ensuring that LSEs meet their RPS and energy efficiency targets, and that all EDUs comply with Cap-and-Trade requirements. CMUA would not recommend using the benchmarks as a basis for measuring or determining compliance with GHG targets, because they still may not capture the positive impacts of efforts that lead to an increase in load (such as transportation electrification).

Reid commented that the CARB methodology utilized in the benchmark proposal unfairly discriminates against the IOUs. Instead, Reid recommended use of CARB's GHG Facility and Entity Emissions Report to determine an individual LSE's emissions requirement based on its most recent pro-rata share of emissions.

PG&E stated that it does not support use of LSE-specific GHG benchmarks, but if they are established, PG&E does not object to staff's proposed methodology. PG&E's main concerns were that an LSE could be required to take a specific action or risk not having its IRP approved, to meet a benchmark that is a point estimate in 2030. PG&E also stated that it is unclear how the Commission will address the multiple and complex issues around load-based GHG emissions accounting, such as the fact that LSEs do not always dispatch resources to meet their load, and are instead required to bid into the CAISO market, which chooses dispatch order. PG&E's comments went on to suggest a specific GHG accounting methodology which we discuss later in this decision, while strongly cautioning against using the ERRA GHG accounting methodology suggested by staff.

SDG&E commented that GHG reduction opportunities are not equally distributed nor can they be achieved on an equal cost basis across all LSEs. In addition, they were concerned that the benchmark proposed does not account for GHG emissions associated with various forms of must-take CHP, IOU portfolio resources purchased on behalf of all customers, emissions based on resources where dispatch is not controlled by the IOUs,

departing load issues related to customer choice, and load growth due to decarbonization of other economic sectors, such as transportation electrification.

### **12.3. Discussion**

As a general proposition, the GHG emission benchmark suggested by staff represents a simple and transparent approach to benchmarking emissions across multiple diverse LSEs. As suggested by SCE, we will adopt it as an option to be used voluntarily by LSEs as an alternative to the GHG Planning Price methodology described in Section 11 of this decision, for LSEs filing alternative IRP plans described further in Section 13 of this decision.

The benchmark is calculated by using assumptions about relative load share of each LSE in 2030, based on the mid-level AAEE version of Form 1.1c of the 2016 IEPR demand forecast published by the CEC. For ESPs, their load share assignments will be based on each ESP's forecast submitted to the CEC in its 2017 IEPR Confidential Form 7.1.

As stated in the staff proposal, this benchmark is intended to serve as a planning instrument and will not serve as a compliance obligation.

As requested by AReM, we clarify that we expect each LSE to file one integrated IRP, not separate IRPs for ESPs that serve customers in more than one IOU territory. The original proposal also requires modification to account for ESPs that do serve customers in more than one IOU territory.

For ESPs in that situation, they will first need to calculate their proportion of direct access load in each IOU territory. Then, for each IOU territory, they will multiply their load percentage by IOU territory by the figure shown in the table below for the relevant IOU, then adding together the benchmark for each IOU area to create one single benchmark for their particular load.

Table 7 below gives the adopted GHG benchmarks that LSEs may utilize, in addition to or instead of the GHG Planning Price, for IRP planning in 2018. The table also gives the 2016 IEPR assumptions upon which these calculations are based, so that

parties understand the methodology that will need to be adjusted based on the 2017 and subsequent IEPs.

**Table 7. Load Projections and GHG Emissions Benchmarks by LSE**

Utility	LSE within Utility Territory	Proportion of 2030 Allowance Allocation Under Cap and Trade	2030 Load (GWh)	Proportion of 2030 Load within EDU	2030 GHG Emissions Benchmark (MMT)
Bear Valley Electric Service	NA	0.1%	137	NA	0.028
Liberty Utilities	NA	0.3%	598	NA	0.121
PG&E	Bundled	33.5%	79,077	85.6%	13.210
	Direct Access		9,520	10.3%	1.590
	Marin Clean Energy		1,950	2.1%	0.326
	Sonoma Clean Power		1,825	2.0%	0.305
PacifiCorp	NA	0.8%	845	NA	0.355
SCE	Bundled	32.8%	77,738	86.3%	13.037
	Direct Access		11,710	13.0%	1.964
	Lancaster Choice Energy		627	0.7%	0.105
SDG&E	Bundled	9.1%	17,538	82.9%	3.480
	Direct Access		3,624	17.1%	0.719

### 13. LSE IRP Filing Requirements

The May 2017 IRP Staff Proposal, specifically Chapter 5, included a suggested approach to the filing of IRPs by individual LSEs, including the procedural manner in which the Commission would consider them. Those items are discussed in this section.

#### 13.1. Staff Proposal

The May 2017 IRP Staff Proposal recommended that all LSEs required to file IRPs submit them as separate applications before the Commission. The proposal then

suggested that the Commission would categorize the applications as ratesetting, because they may request that the Commission authorize procurement, and consolidate all of the separate applications, so that they may be considered in aggregate. The proposal also suggested that this rulemaking remain open to consider additional policymaking in parallel with consideration of the individual IRP filings.

In addition, the IRP Staff Proposal introduced the concept of two types of IRP filings: Standard Plans and Alternative Plans. The type of plan required would depend on the amount of load projected to be served by the LSE. Standard Plans would be intended for the large IOUs, ESPs, and CCAs, while Alternative Plans would be designed for use by smaller LSEs (Type 1) as well as multi-jurisdictional utilities (Type 2).

### **13.2. Comments of Parties**

On the subject of requiring IRPs to be filed by individual applications by each LSE, this part of the proposal was supported by the following parties: PG&E, SCE, SDG&E, CEJA/Sierra Club, and POC. These parties felt that requiring an application process with a noticed vote of the Commission was important to ensure transparency and a public process.

Shell, AReM, and WPTF commented that ESPs and CCAs should not be required to file their IRPs by application. Instead, they proposed an informal advice letter process, a compliance filing (similar to the process used in the RPS proceeding), or informal implementation plans. CalCCA also proposed using implementation plans rather than applications.

AReM and WPTF also objected to the idea that the Commission would designate individual IRP applications as “ratesetting,” arguing that the Commission has no ratesetting authority over ESPs, and does not regulate the rates or terms and conditions of service of ESPs or CCAs. Their comments also emphasized the importance of protecting confidential information in filings.

PacifiCorp’s comments voiced concern about timing, because PacifiCorp already submits its IRP every other year (in odd numbered years) and an IRP Update (in even

numbered years). PacifiCorp requested that they be authorized to either 1) submit any IRP submitted to another public regulatory entity within the past two years or 2) utilize its IRP Update (along with the full underlying IRP) in compliance with the Type 2 Alternative Plan requirements suggested by staff in the May 2017 IRP Staff Proposal.

CalCCA also argued that SB 350 only requires CCAs to “provide,” and not formally “file” or “submit” their IRPs to the Commission for “certification.”

Parties also commented extensively on the May 2017 IRP Staff Proposal suggestion to designate Standard and Alternative Plan types. SCE and SDG&E felt that all requirements should be applied comprehensively and consistently to all LSEs, regardless of size. They felt that the standard of review should be the same for all LSEs. LSA comments shared this general view.

CalCCA proposed a third type of plan to apply to all CCAs with over 700 GWh of load, where use of the GHG Planning Price and compliance with the RSP and IRP template should be voluntary. They did not object to the distinction between Standard and Alternative Plans for electrical corporations. Instead, they proposed a separate process for CCAs, designed to accomplish “certification.”

Liberty Utilities supported use of an Alternative Plan for both small and multi-jurisdictional utilities.

Shell did not support the load threshold as the rationale for determining eligibility for different types of plans, arguing it should instead be based on LSE type. WPTF also argued that all non-utility LSEs should file Alternative Plans. Reid objected to two different plan types, calling the idea “administrative discrimination.”

### **13.3. Discussion**

As discussed above in Section 2 of this decision, all LSEs subject to Section 454.52, except the electrical cooperatives exempted by AB 759 (Dahle, 2017) are required to file their IRPs by no later than May 1 of each even-numbered year, except in 2018 when the due date will be June 1.

For practical and administrative reasons, we modify the original staff proposal on the mechanisms of IRP filing. Instead of requiring the filing of separate applications by each LSE, we will require that each LSE file its IRP in this rulemaking proceeding, R.16-02-007, as a “compliance filing.” In this way, all of the IRPs will automatically be consolidated within this proceeding for our consideration. We intend to re-categorize this rulemaking as “ratesetting” in the near future, to account for the fact that some LSEs may request consideration of procurement authorizations within their IRP filings.

We will also recognize two categories of LSE Plans as proposed by staff, Standard and Alternative, based primarily on LSE load forecasted to be served over the IRP planning horizon. This is for practical reasons as well. Size of load served is a simple way to distinguish between LSEs that will have relatively simple systems and those which are inherently more complex, due to size or geography. Larger load also tends to correlate with the potential for a greater impact on the rest of the electric system. We will also make a special provision for PacifiCorp, regardless of their load size, since they already prepare an IRP every two years, as required by other jurisdictions. PacifiCorp will be required to file the IRP they already prepare, with any supplemental information about disadvantaged communities required in this decision that is not already covered in their IRP filing prepared for those other jurisdictions.

The Commission will initially assign a load forecast for the IRP planning horizon to each LSE, except ESPs, based on the mid AAEE version of Form 1.1c of the 2017 IEPR demand forecast.<sup>18</sup> Each ESP will be assigned the load forecast submitted to CEC in its 2017 IEPR Confidential Form 7.1.

The load forecast assignment provides an initial direction as to which plan type an LSE may be eligible to file, and LSEs are required to use this load forecast in developing

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<sup>18</sup> Since the 2017 IEPR is not yet final, an example of the corresponding form from the previous (2016) IEPR demand forecast can be found online at: [http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN216264\\_20170227T144018\\_Corrected\\_LSE\\_and\\_BA\\_Tables\\_Mid\\_Baseline\\_Mid\\_AAEE.xlsx](http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN216264_20170227T144018_Corrected_LSE_and_BA_Tables_Mid_Baseline_Mid_AAEE.xlsx).

their plans. If the load forecast assigned to an LSE is  $\geq 700$  GWh in California in any of the first five years of the IRP planning horizon, then the LSE should file a Standard Plan. If the load forecast assigned to an LSE is  $< 700$  GWh in California in each of the first five years of the IRP planning horizon, the LSE may be eligible to file an Alternative Plan (see Table 8).

An LSE's filing eligibility may change in subsequent IRP cycles depending on changing load assignments and/or LSE-submitted documentation validating its eligibility.

Table 8. Plan Type Required for LSEs

LSE Type	LSE Name*	Balancing Authority Area	LSE Plan Designation
Large IOU	Pacific Gas and Electric	CAISO	Standard
	Southern California Edison	CAISO	Standard
	San Diego Gas and Electric	CAISO	Standard
CCA	CleanPowerSF	CAISO	Standard
	Lancaster Choice Energy	CAISO	Alternative
	Marin Clean Energy	CAISO	Standard
	Sonoma Clean Power	CAISO	Standard
Small IOU	Bear Valley Electric Service	CAISO	Alternative
	Liberty Utilities	NV Energy	Alternative
Multi-Jurisdictional IOU	PacifiCorp	PacifiCorp West	Alternative
ESP	3Phases Renewable Energy LLC	CAISO	TBD
	Agera Energy, LLC	CAISO	TBD
	Calpine Power America CA, LLC	CAISO	TBD
	Commerce Energy Inc.	CAISO	TBD
	Commercial Energy of California	CAISO	TBD
	Constellation New Energy Inc.	CAISO	TBD
	Direct Energy Business LLC	CAISO	TBD
	EDF Industrial Power Services, LLC	CAISO	TBD
	Gexa Energy California, LLC	CAISO	TBD
	Glacial Energy of California, Inc.	CAISO	TBD
	Liberty Power Holdings	CAISO	TBD
	Next Era Energy	CAISO	TBD
	Pilot Power Group	CAISO	TBD
	Sempra Energy Solutions LLC (Noble Energy)	CAISO	TBD
	Shell Energy North America	CAISO	TBD
	The Regents of the University of California	CAISO	TBD
	Tiger Natural Gas Inc.	CAISO	TBD

\*This list is not exhaustive and may exclude the names of several ESPs; however, all CPUC-jurisdictional LSEs are required to file IRPs except as discussed in Section 3 of this decision.



The basic LSE IRP requirements are described in this section. The Commission will not approve or certify any submitted IRP that does not satisfy the requirements described below and in the templates attached to this decision.

All requirements and instructions for Standard LSE Plans are described in the Standard LSE Plan Template (Attachment A to this decision). LSEs preparing a Standard Plan will be expected to use this template, in addition to a Standard Plan Data Template that will be posted by the Commission on our web site and continuously maintained by our staff.

To the extent that information within individual LSEs' Plans is not market-sensitive and confidential, such information will be made publicly available.

The Commission will recognize two types of Alternative LSE Plans: Type 1 and Type 2.

LSEs eligible to submit Type 1 Alternative LSE Plans include small IOUs, electric service providers, and community choice aggregators assigned a load of less than 700 GWh in California in each of the first five years of the IRP planning horizon. PacifiCorp is eligible to submit a Type 2 Alternative LSE Plan.

LSEs filing an Alternative LSE Plan are not required to complete or submit a Data Template.

LSEs filing Type 1 Alternative Plans will be required to provide the following:

- a. California Energy Commission (CEC) Form S1
- b. CEC Form S2 or Energy Information Administration (EIA) Form 861 or EIA Form 861S
- c. CEC Power Content Report
- d. A description of treatment of disadvantaged communities, described in Section 6 of this decision.

LSEs filing Type 2 Alternative Plans may submit any IRP submitted to another public regulatory entity within the previous calendar year (i.e., if LSE Plans are due to the CPUC in 2018, then the eligible LSE may submit its 2017 IRP as its Type 2 Alternative Plan). If this IRP does not already include a demonstration of how disadvantaged

communities were considered, a separate demonstration must be submitted that satisfies the requirements for disadvantaged communities as described in Section 6 of this decision.

#### **14. PCM Next Steps**

This section addresses proposed next steps for Commission staff to lead a process to calibrate and vet PCM and apply it to evaluating the reliability consequences of the aggregated LSE Plans (ultimately forming the PSP).

##### **14.1. Staff Proposal**

The May 16, 2017 IRP Staff Proposal, in Chapter 5, contained a general outline of PCM steps that the Commission staff proposed to take to review the individual LSE Plans. Attachment E to the proposed RSP ruling from September 19, 2017 contained a more developed and comprehensive proposal to utilize PCM, both for evaluating the RSP and portfolio recommendation, as well as for evaluating the collection of individual IRP filings in order to recommend the PSP. This proposal was also preliminarily discussed at a staff-hosted webinar meeting of the Modeling Advisory Group on September 6, 2017.

In particular, staff recommended the use of the Strategic Energy Risk Valuation Model (SERVM) to conduct PCM of the system portfolios being considered in the IRP process. The ultimate purpose of this modeling is to evaluate the system reliability and performance of the PSP portfolio in higher operational detail and under a wider distribution of conditions than were considered in RESOLVE modeling. Because the SERVVM model is already used in the Commission's Resource Adequacy proceeding, staff believed it would be reasonable and efficient to leverage that PCM experience for use in the IRP process. Staff proposed some modifications to the resource adequacy requirements for planning reserve margin (PRM) and effective load carrying capability (ELCC) calculations.

In addition, staff suggested that the insights gained from the California Energy Systems for the 21<sup>st</sup> Century (CES-21) research project may be useful for enhancing IRP PCM activities in the current or future IRP cycles. The CES-21 project also used the

SERVIM model and investigated very similar questions to those that the IRP PCM activities seek to answer.

Staff proposed to continue to utilize the Modeling Advisory Group, formed in this proceeding, to allow staff and parties to interact informally and collaborate on modeling-related work.

After receipt of the individual LSE IRPs, staff proposed to conduct additional PCM steps to evaluate and recommend a PSP. Staff proposed to use SERVIM to measure operational performance and verify satisfaction of the PRM requirements.

#### **14.2. Comments of Parties**

A number of parties provided detailed comments on the modeling approach proposed by Commission staff.

CAISO provided extensive comments in support of PCM to measure system reliability requirements, as well as validate achievement of GHG emissions levels. They were concerned that RESOLVE's simplified assumptions may mask curtailment issues associated with large amounts of solar, for reliability purposes, as well as understate emissions from natural gas-fired resources because of additional cycling associated with the RESOLVE portfolio. Process wise, the CAISO suggested having PCM results from multiple parties conducting the modeling vetted formally on the record of this proceeding.

Calpine was concerned about the estimated number of starts of natural gas plants estimated both by Commission staff and by CEJA and Sierra Club in their comments and RESOLVE analysis. They also commented that a higher PRM may be required to meet a reliability target, as long as DERs are treated as static load modifiers.

CEJA and Sierra Club request additional PCM work to evaluate air quality impacts and guide planning to minimize emissions, with a particular focus on plant cycling. They felt that RESOLVE was not the appropriate tool to examine the true air quality impacts.

CESA commented that if modeling resources are constrained, then PCM work should focus on intra-hour modeling of a single study year, rather than hourly modeling of multiple years. They identified significant sub-hourly variability in renewable generation that could make it infeasible to rely heavily on renewable curtailments to provide load following and regulation services. CESA also noted that load following needs are non-linearly related to load and variable renewable production. This relationship should be better represented in PCM. Finally, CESA suggested that curtailment amounts and costs should be more carefully evaluated using PCM.

Imperial County recommended PCM reporting not only on GHG emissions, but also local air pollutants in disadvantaged communities. They also noted the importance of studying a year with Diablo Canyon retired to assess its impact on system emission with more accuracy.

CLECA was concerned about the proposed “supply side” treatment of BTM PV, which differs from how it is treated in resource adequacy modeling for calculating ELCC values. CLECA felt the goal should be consistent treatment between IRP and resource adequacy. CLECA also questioned RESOLVE’s ability to model ramping, flexible needs, and resource types that can provide flexibility.

CMUA supported the CAISO call for PCM to verify operations, and called for more PCM to examine gas retirement sensitivities.

Eagle Crest, LS Power, and National Grid all commented about the need for PCM to ensure adequate operational flexibility, in coordination with the CAISO Flexible Resource Adequacy Criteria and Must Offer Obligation 2 process.

GPI commented, as they have elsewhere, with a recommendation for GHG accounting for biomass and biogas facilities. They also felt that the staff sensitivity analysis did not adequately consider the uncertainty bound around each sensitivity and posited that the total cost metric of one sensitivity would not be distinguishable from another after proper consideration of uncertainty.

LSA supported the staff proposal for PCM in IRP and benchmarking between RESOLVE and SERVVM.

NRG stated its concerns about validating reliability requirements only in the summer months, instead suggesting all months be checked. They also strongly agreed with modeling BTM PV as generation rather than load, and also commented on the need to model the increasing risk of extreme weather events.

ORA commented that they were generally in support of the staff recommendation, and that PCM is a more accurate tool to measure PRM. They also suggested modeling 2026, and suggested providing guidance to LSEs for a range of ELCC values based on a range of wind and solar proportions, given the expected deviation of LSE plans from the RSP.

PG&E objected to the staff proposal's requirement to map LSE resource selections back to a specific RESOLVE resource identified in the RSP. They felt this idea was not necessary or practical. PG&E also agreed with the CAISO that PCM results should be vetted on the record of this proceeding.

SCE's main concern in comments was that the staff PCM reliability validation may not be ready in time for LSEs to use in their individual IRP preparation. SDG&E was similarly concerned about parallel PCM work alongside LSE IRP development, and suggested that in future cycles, the PCM validation occur before adoption of the RSP.

UCS's comments questioned why we would use SERVVM to check the PRM. UCS stated that since the PRM constraint was not binding in the 42 MMT Scenario, then using the PRM to determine system shortfall may lead to overlooking other important aspects of operational performance and reliability.

VEA commented that the inputs from RESOLVE to PCM need to be location-specific.

Finally, Vote Solar stated that RESOLVE should be replaced with a superior model such as Aurora in subsequent rounds of analysis. They were concerned about RESOLVE's lack of locational bottom-up distribution level modeling with DERs as

candidate resources. Vote Solar felt that neither RESOLVE nor SERVVM can accurately represent the variability of net loads or the ramping needed to ensure that net loads are met in any given period.

#### **14.3. Discussion**

We agree with Commission staff's proposal to use PCM, with the SERVVM tool, to develop a PSP, at least for this IRP cycle. It is likely that modeling techniques can be improved, so we will remain open to other options in the future.

To be consistent with the resource adequacy requirements for the planning reserve margin, we will require verification that the PRM requirements are met in each month of the study year, and that modeling and counting conventions align with those used in the resource adequacy proceeding to the greatest extent possible.

We will also ask Commission staff to continue the MAG process and conduct PCM calibration and vetting with interested parties, with the RSP adopted in this decision as a starting point, during the first half of 2018. This will be an informal effort, culminating in staff posting of additional salient information for use by parties intending to conduct their own PCM to support or inform their IRP filings. Staff and any other parties conducting modeling will be asked to share their results and recommendations around April 2018. All parties will then have a formal opportunity to comment on the staff recommendations for the outcome of the calibration and vetting process, on the record in this proceeding, likely culminating in an ALJ ruling adopting the assumptions and other approaches to utilize in this round of IRP for analysis of the proposed PSP.

Further details on the calibration and vetting process, as well as the PCM scope, conventions, and steps, are included as Attachment B to this decision. All parties conducting PCM to support their IRP filings shall follow the guidance outlined in Attachment B.

#### **15. Other Next Steps**

This section describes several areas where Commission staff recommended additional work in the proposed RSP.

### **15.1. Development of a Common Resource Valuation Methodology**

Development of a CRVM was part of Commission staff's recommendations for policy actions by the Commission in the RSP. It is discussed further in this section.

#### **15.1.1. Staff Recommendation**

Staff recommended that a CRVM would be designed to capture the resource valuation attributes as defined in IRP modeling so that they can be reflected in procurement activities and bid evaluation.

Commission staff proposed to work together with stakeholders to develop a CRVM proposal to ensure that the costs and benefits used in IRP planning are reflected in bid evaluation and program funding authorization across resource types. Staff proposed to take a phased approach that prioritizes CRVM development for resource areas that are likely to see procurement activity in response to the 2017-18 IRP. For example, renewable procurement, in coordination with the RPS program, which already contains a requirement for least-cost best-fit evaluation, would be a logical starting point.

#### **15.1.2. Comments of Parties**

Numerous parties generally supported the idea of creation of a CRVM, including PG&E, SCE, AEE, CEJA/Sierra Club, EDF, NRG, NRDC, Tesla, AWEA, Vote Solar, Ormat, and CEERT. Parties also generally expected to be included in the development process through public workshops and other opportunities to comment.

PG&E also commented that LSEs should retain the ability to use their own proprietary methodologies, at least in addition to any CRVM. CEJA/Sierra Club and ORA suggested specific inclusion of impacts on disadvantaged communities. AReM sought clarification that the CRVM would only apply to IOUs. And multiple parties suggested that any CRVM development should be comprehensive and iterative, not sequential or segregated by resource type.

Some parties also commented that development of a CRVM should be a low priority, including SDG&E, CAISO, Imperial County, SoCalGas, and UCS.

No parties opposed CRVM development in their comments.

### **15.1.3. Discussion**

We generally agree that staff should continue to pursue development of a CRVM in 2018, in coordination with the least-cost best-fit methodology development and reform in the RPS program, where possible. Staff should also include exploration of other existing methodologies, including the consistent evaluation protocol used for storage resources, and the cost-effectiveness methodologies used for DERs, including the avoided cost calculators used there. Ongoing work in the Distribution Resource Planning area to identify locational net benefits may also prove useful. Any staff work products leading to recommendations for Commission adoption will be publicly vetted with opportunities for stakeholder input.

## **15.2. Natural Gas Fleet Impacts**

Another of the policy areas included in the proposed RSP for potential Commission action was examination of impacts on the natural gas fleet in California.

### **15.2.1. Staff Recommendation**

The proposed RSP ruling stated that modeling results showed that, other than the OTC plant retirements, the other natural gas resources already delivering energy to the CAISO are needed for reliability and renewable integration purposes through 2030 to reduce overall system costs. Keeping existing gas capacity available was predicted as more cost-effective than retiring gas plants and acquiring new ones, or alternative replacement capacity, to serve reliability and integration needs.

However, because the RESOLVE model handles classes of resources and not individual plants, and because the expiration of the ITC and PTC would drive early procurement of solar and wind resources, lowering utilization of the natural gas capacity in the near term prior to retirement of the Diablo Canyon nuclear plant in the medium term, staff recommended that more analysis was needed to identify the types of gas plants, or plant attributes, that are most desirable and most needed for reliability. Further work was also identified as needed on how to design procurement or contractual



mechanisms to support sustaining the desirable natural gas plants and characteristics in the near and medium term to support attainment of the 2030 GHG target sector wide at least cost while maintaining reliability.

Commission staff proposed to work with the CAISO to study options for ensuring ongoing viability for renewable integration and resource adequacy/reliability purposes.

### **15.2.2. Comments of Parties**

Numerous parties commented on this aspect of the staff recommendation. Some fundamental needs raised by parties included the need for better location-specific understanding of the value of natural gas resources on the system, identification of operational challenges that will emerge or be exacerbated as the amount of renewable generation grows, whether services currently provided by natural gas resources can be economically replaced by other resources, and how to ensure least-cost reliability through CAISO market mechanisms and capacity development in the resource adequacy or IRP processes.

Parties generally supporting further study and offering detailed recommendations included CAISO, Calpine, CEERT, CEJA/Sierra Club, CESA, CMUA, CURE, EDF, IEP, Imperial County, LS Power, LSA, NRG, ORA, PG&E, Range, SCE, SDG&E, UCS, and Vote Solar.

Eagle Crest and National Grid both opposed further study on this topic by the Commission, instead suggesting reliance on the CAISO.

### **15.2.3. Discussion**

We agree with staff and numerous parties that this is an important policy area for further work. At this stage, we are not offering specific direction for a particular study on natural gas fleet issues, but will direct staff to continue to work with the CAISO to study the most important attributes of the natural gas fleet and work in coordination with the resource adequacy proceeding activities. Any further examination of these issues will be with sensitivity to the location-specific aspects of natural gas generation, including impacts on disadvantaged communities and air quality implications.

### **15.3. Electrification Issues**

Though not included in the list of recommended near-term Commission policy actions in the proposed RSP, we are cognizant that our actions with respect to setting GHG targets and planning for emissions reductions in the electricity sector should not be done in isolation. While we focused, for this first round of IRP analysis, on the electric sector, there is no question that there are important interactions between, in particular, the transportation sector and the buildings sector, that can help or hurt the state's chances of meeting its GHG targets in 2030 economy wide.

Numerous parties, including most vociferously SCE, commented on the importance of our policies for the electric sector not creating disincentives for electrification of transportation and building loads.

Thus, we anticipate that in early 2018, we will begin to address both the technical and policy questions associated with these cross-sectoral issues, in order to begin to formulate a more comprehensive strategy, in coordination with CARB and CEC. While the 2018 individual LSE IRPs may not be required to incorporate these cross-sectoral questions, LSEs are free to propose how to address specific issues in their filings. We expect a more comprehensive cross-sectoral approach to be the subject of the next IRP cycle.

As a preview, the types of questions we anticipate tackling include:

- How to estimate expected load impacts from vehicle or building electrification
- The types of investments by LSEs that would produce the greatest GHG benefits through electrification
- How to account for the GHG benefits of electrification while potentially increasing the GHG emissions in the electric sector.

### **16. Reimbursable Funding to the Commission for Technical Support**

To bring the IRP process to this point, Commission staff have benefitted from support from technical consultants to conduct RESOLVE modeling and assist with other planning tasks. Meeting the state's future GHG reduction goals while maintaining

reliability and minimizing impacts on ratepayers will require further development and refinement of the analytical framework and tools that are being used for the IRP process. This need will be an ongoing one through the next several IRP cycles.

The California Legislature's Annual Budget Act gives the Commission certain specific and limited ongoing reimbursable expenditure authority. Prior to exercising this authority, the Commission must issue a decision that identifies the contracting activities to be undertaken by the Commission, and the costs subject to reimbursement by utility companies. This decision serves that purpose.<sup>19</sup>

Commission staff anticipates technical support and consulting on the following types of tasks, including, but not limited to:

1. Post-2030 Cross-Sectoral Analysis: Developing and implementing technical methods to establish an economy-wide and regional roadmap for achieving the State's 2030/2050 GHG reduction goals in order to better plan for the risks and opportunities (e.g., accelerated electrification and inter-state benefits) in the electric sector that may accompany GHG reduction efforts in other sectors of California's economy, as well as the economies of neighboring states;
2. Regional Resource Planning: Analyzing of regional opportunities to achieve the GHG reduction and reliability goals of individual Western states while reducing costs through improved alignment of energy and capacity markets, transmission planning, and building and transportation electrification; this includes coordinating closely with other California State agencies, including CARB, CEC, and CAISO, and sister agencies in other states, particularly Washington and Oregon as part of the Joint Action Framework on Climate Change;
3. Electrification Planning: Conducting an implementation assessment for accelerating the electrification of other sectors of California's economy, with a focus on transportation and buildings; this would include developing a planning framework that addresses the roles and responsibilities of the various state agencies that must be involved in electrification, different types of LSEs, diverse private sector entities, as well as different segments of end-users;

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<sup>19</sup> See Budget Act of 2010, Stats. 2010, Ch. 712, Item 8660-001-0462(6).

4. Ongoing Updates to IRP Assumptions: Updating and refining assumptions used for the purpose of determining the optimal portfolio of resources needed for reducing GHG emissions while maintaining reliability and meeting other state requirements at the least cost; this includes assumptions related to the cost of renewable energy resources, fossil resources (including existing fossil resources), storage, and transmission and distribution infrastructure;
5. Optimizing DERs: Identifying and addressing technical challenges associated with both optimizing DERs in integrated resource planning, and linking planning with procurement; examples include: BTM solar PV, storage, demand response, building electrification, and electric vehicles;
6. Evaluating Current and Emerging Technologies: Conducting engineering and economic assessments of current and emerging technologies in order to identify the potential for, and barriers to, future cost reductions, increased market deployment, and market transformation; example technologies include: renewable energy generation, energy storage, grid integration, and GHG emissions reduction, including electrification and fuel switching technologies. This analysis would be used to inform a technology road map for achieving 2030 and 2050 GHG targets. This roadmap would inform the IRP planning process and future investments in the electric sector.
7. Compliance Assessments: Other tasks as necessary to sustain and improve the technical basis of IRP in order to better realize the goals for which it was established; examples include: performing technical and implementation analysis of new compliance mechanisms for ensuring that the costs of GHG emissions reductions are shared equitably across ratepayers of bundled and unbundled customers; facilitating the exchange and communication of technical information among parties, other agencies, and the public.

For these purposes, beginning with the 2017-18 fiscal year, we will authorize the expenditures of up to, but no more than, \$3 million annually for up to six years, for a total budget not to exceed \$18 million. The maximum nominal value of a contract shall not exceed \$18 million. The annual funds may be carried forward and expended in a subsequent year. If not spent within six years, the funds may be spent in subsequent years, but still may not exceed the maximum total.

The Commission's Executive Director will approve the expenditures and seek reimbursement from PG&E, SCE, and SDG&E. Reimbursement will be sought from these three IOUs on a proportional basis in relationship to their annual retail sales reported in their most recent IRP approved by the Commission. PG&E, SCE, and SDG&E should establish an IRP Costs Memorandum Account (IRPCMA) by submitting a Tier 2 advice letter within 30 days of the date of this decision. In the advice letters, each IOU must make clear its plan for maintaining and administering its new or modified IRPCMA in a manner that will meet the requirements of this decision. The IOUs are authorized to record IRP third party technical support costs into the IRPCMA. These costs may be recorded when paid, for later recovery via generation rates.

Similar to actions we have taken in the past,<sup>20</sup> we will excuse other LSEs from these funding requirements, either because their load is small or because our authority does not extend to their rates paid by customers.

#### **17. Comments on Proposed Decision**

The proposed decision of ALJ Fitch in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on \_\_\_\_\_ by \_\_\_\_\_. Reply comments were filed on \_\_\_\_\_ by \_\_\_\_\_.

#### **18. Assignment of Proceeding**

Liane M. Randolph is the assigned Commissioner and Julie A. Fitch is the assigned ALJ in this proceeding.

#### **Findings of Fact**

1. A two-year IRP cycle is an appropriate replacement for the previous LTPP planning process conducted by the Commission for at least the past decade.

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<sup>20</sup> See, for example, D.06-10-050 at 54.

2. Section 454.51 creates a responsibility for the Commission to require, review, and approve IRP filings from all load-serving entities.

3. Commission staff can and should continuously improve modeling and analysis techniques to represent the optimal electric resource portfolio and appropriate GHG emissions targets for the electric sector.

4. Selecting 42 MMT as the GHG emissions target for the electric sector in 2030 is within the range identified for the sector by CARB, represents an increase in momentum relative to current policies, and is not so burdensome as to discourage electrification that would benefit the state as a whole.

5. The Default Scenario for GHG emissions in 2030 is not aggressive enough and the 30 MMT Scenario will create too high a cost burden on the electric sector relative to other sectors of the California economy.

6. The capacity expansion modeling conducted by Commission staff in this proceeding did not identify a need for near-term procurement of out-of-state wind, geothermal, or pumped hydro storage resources beginning in 2018.

7. The optimal portfolio analyzed by Commission staff and represented in the proposed RSP includes additional energy efficiency, BTM solar, renewables, and battery storage.

8. The total electric resources shown in Figure 3 and the incremental resources shown in Figure 6, for 2030, represent a reasonable portfolio to adopt in compliance with Section 454.51 requirements.

9. Individual LSEs may be able to identify optimal portfolios to serve their load that differ from the mix identified in the Commission reference system portfolio. LSEs should be given flexibility to propose alternate portfolios to meet their customers' needs, in addition to conforming portfolios, while justifying any deviations from the reference portfolio.

10. It is unclear whether requiring procurement of additional renewables outside of the RPS requirements in the context of this IRP cycle could result in cost savings due to

the expiring federal tax credits (PTC and ITC). Ordering such procurement here would also require settling complex issues of cost allocation and load forecasting.

11. The Default Scenario modeled by Commission staff as part of the proposed RSP is appropriate for use as the reliability base case by the CAISO's TPP in 2018-19.

12. The 42 MMT Scenario adopted as the RSP is appropriate for use as the policy-driven case for the CAISO's TPP in 2018-19.

13. An LSE plan should be able to demonstrate conformance with the RSP by utilizing either the GHG Planning Price identified in Table 5 or the GHG Emission Benchmark identified in Table 7 of this decision.

14. An LSE filing a Standard Plan, as defined in this decision, should use the GHG Planning Price identified in Table 5, for developing its 2018 IRP filing.

15. The GHG Adder identified in Table 6 of this decision is appropriate for replacing the GHG Adder in D.17-08-022 and for use in evaluating cost-effectiveness of DERs when a marginal GHG abatement cost is required.

16. A GHG emission benchmark based on relative load share of each LSE in 2030 as reported to the CEC as part of the IEPR process is appropriate for use as a planning instrument, including for LSE-specific targets to be set in coordination with CARB, but not as a compliance obligation.

17. LSE-specific GHG emissions accounting should be required to follow the specific requirements in Attachment A of this decision related to the "clean net short" method proposed by PG&E.

18. It is appropriate to distinguish between Standard Plans and Alternative Plans for different types of LSEs filing IRPs. All LSEs with projected load greater than 700 GWh over a rolling three-year average should be required to file Standard Plans, with those entities with smaller loads allowed to file Alternative Plans, except PacifiCorp, which should be allowed to file its IRP filed with another jurisdiction within the past two years, along with any supplemental information related to the requirements associated with disadvantaged communities discussed in Section 6 of this decision.

19. Commission staff should conduct PCM activities in order to prepare to create the PSP based on aggregated LSE Plans.

20. The MAG process should continue informally, and parties should have an opportunity to comment on PCM approaches and outputs formally on the record of this proceeding.

21. Utilizing common assumptions in PCM will facilitate comparison of results and analysis of the reliability implications of the PSP, among other metrics.

22. The SERVIM model is an appropriate tool for use in this round of IRP to calibrate and vet PCM for use in developing the PSP.

23. The Commission requires ongoing technical support funding to support the IRP process adopted in this decision, because of its inherent complexity and requirements to achieve many different objectives, including reducing greenhouse gases, maintaining reliability, and minimizing ratepayer impacts.

### **Conclusions of Law**

1. The Commission should adopt a two-year IRP cycle as the planning process to replace the former LTPP proceeding planning process.

2. The odd-numbered years of the IRP cycle should include analysis and modeling, utilizing the most recent CEC IEPR assumptions, leading to the adoption of a Reference System Plan, to be used in the preparation of individual LSE IRPs as well as the CAISO TPP commencing in even-numbered years.

3. The even-numbered years of the IRP cycle should include the filing of individual LSE IRPs, aggregated by Commission staff for the Commission to adopt a PSP, and leading to the adoption or modification of individual LSE IRPs and associated procurement authorizations, as appropriate.

4. The PSP should be transmitted to the CAISO as the policy-driven case for its TPP process commencing in odd-numbered years.

5. Section 454.52(e) exempts a small electric cooperative from the requirements for filing an IRP if it has electrical demand not exceeding 700 gigawatthours per year, as



determined on a three-year average commencing with January 1, 2013. Electric cooperatives meeting this criterion should be required to submit information substantiating their eligibility for this exemption at the same time other LSEs are required to submit their IRPs, every two years.

6. Sections 454.51 and 454.52 do not create any exception from the Commission's responsibilities with respect to electric service providers. The Commission's authority includes review and approval of ESP IRP filings.

7. The existence of local governing boards for CCA LSEs does not diminish or supplant the Commission's authority over IRP filings of CCAs.

8. The Commission's role with respect to review of CCA IRPs is substantive and requires the Commission to certify the CCA's plan as consistent with all of the requirements of Section 454.52(b)(3), as well as Section 454.51(d) and (e), which includes the Commission's authority over certain procurement-related activities of CCAs, as well as their renewable integration responsibilities.

9. Section 454.51(b) and (c), Section 454.52(a)(1)(C), and Section 454.52(b)(2) apply only to IOU LSEs.

10. The Commission should continue modifications and improvements to modeling to represent the optimal electric resource portfolio required by Section 454.52 and to choose the appropriate GHG emissions target for the electric sector.

11. The Commission should adopt 42 MMT as the GHG target for the electric sector for 2030 for this IRP cycle.

12. The Commission is required, by Section 454.52, to "ensure that load-serving entities: (F) strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities..." and "(H) minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code."

13. For purpose of the IRP process, a disadvantaged community should be defined as a community scoring in the top 25 percent according to the most recently available version of the CalEPA CalEnviroScreen Tool.

14. The Commission should require all LSEs to describe in their IRP filings their treatment of issues related to disadvantaged communities.

15. The Commission should require a showing from any LSE seeking to acquire new or re-contract with existing natural gas resources as part of its IRP filing, justifying why the need met by such a resource cannot be met by another, lower-emitting resource.

16. The Commission should continue to evaluate the need for long lead-time resources, including out-of-state wind (and other renewables), geothermal, and pumped hydro storage (and other bulk storage) resources in subsequent IRP cycles, but should not order procurement activities for these types of resources at this time.

17. The Commission should adopt the reference system portfolio represented by Figure 3 with incremental resources represented in Figure 6 as a reasonable guide for IRP planning in 2018.

18. The Commission should allow flexibility for LSEs to propose alternate portfolios, in addition to a conforming portfolio, using the reference system portfolio as a guide, and justifying the reason for any deviations.

19. All LSEs should be required to continue to comply with the existing energy efficiency, RPS, and resource adequacy requirements.

20. There is enough uncertainty about the potential benefits of additional renewable procurement now to attempt to capture expiring federal tax credits that the Commission should not order additional procurement now.

21. The Commission should forward the Default Scenario as the reliability base case and the 42 MMT Scenario as the policy-driven case to the CAISO for use in its 2018-19 TPP. Commission staff should continue to work with CEC and CAISO staff to identify the necessary geographic granularity to make this feasible, including utilizing the RETI 2.0 work to the extent possible.

22. The GHG Adder in Table 6 should be made available to replace the GHG Adder adopted in D.17-08-022 for use in the IDER proceeding and any other proceedings that rely on assumptions about the avoided GHG costs of DERs for evaluating cost-effectiveness.

23. The Commission should allow LSEs to utilize a GHG Emission Benchmark, as shown in Table 7 in this decision, to identify their GHG emissions obligations.

24. An LSE should be required to create a conforming portfolio to the RSP by utilizing either the GHG Planning Price or their GHG Emissions Benchmark, along with the common assumptions utilized by Commission staff in creating the RSP, to be included in its IRP. In addition, each LSE may identify one or more alternate portfolios, but should be required to justify why any alternate portfolio, including any portfolio identified as “preferred,” is preferable to the conforming portfolio.

25. The Commission should require all LSEs to identify the emissions associated with their proposed portfolios in their individual LSE Plan filings to follow the methodology proposed by PG&E and specified in Attachment A of this decision, identified as the “clean net short” method.

26. LSEs should be distinguished by load size for purposes of filing Standard or Alternative IRPs based on their load forecast from the CEC’s IEPR process, specifically the mid-AAEE version of Form 1.1c, except for ESPs, which should utilize Confidential Form 7.1.

27. LSEs required to file Standard Plans should be required to submit all information contained in Attachment A to this decision.

28. LSEs filing Alternative Plans should not be required to submit a Data Template.

29. The reliability implications of the RSP and the aggregated LSE Plans leading to the PSP should appropriately be evaluated based on existing resource adequacy requirements, including monthly planning reserve margin requirements.

30. The Commission should continue work on development of a common resource valuation methodology, analysis of natural gas fleet impacts of the IRP requirements, and planning for increased electrification, in preparation for the next cycle of IRP.

31. The Commission should require \$3 million per year for the next six years, in reimbursable funding, on a proportional basis reflected by load forecast, from the three large IOUs, to fund technical assistance for the IRP process adopted in this decision.

32. PG&E, SCE, and SDG&E should be authorized to establish a memorandum account to record IRP technical contractor costs, with amounts not to exceed \$18 million across the three IOUs.

## **O R D E R**

### **IT IS ORDERED that:**

1. The Commission hereby institutes a two-year integrated resource planning process, with each cycle to commence in an odd-numbered calendar year. All electricity load-serving entities, including electrical cooperatives, investor-owned utilities, community choice aggregators, and ESP shall file and serve individual integrated resource plans (IRPs), as further specified in this decision, on May 1 of each even-numbered calendar year, except for 2018, when the filing date shall be June 1. Individual IRPs shall be filed and served in the open IRP rulemaking docket relevant and available at the time of the deadline.

2. Any electrical cooperative, as defined in Public Utilities Code Section 2776, whose annual electrical demand does not exceed 700 gigawatt hour, as determined on a three-year average commencing with January 1, 2013, shall be exempt from the requirements to file an integrated resource plan outlined in this decision. To qualify for this exemption, such an electrical cooperative shall file information substantiating its eligibility for this exemption on the same time schedule and in the same manner outlined in Ordering Paragraph 1 for all load-serving entities filing integrated resource plans.

3. In odd-numbered years, the Commission will analyze and adopt an optimal electric resource portfolio for its load-serving entities and recommend a greenhouse gas target for the electric sector in California to the California Air Resources Board, in coordination with the California Energy Commission.

4. The integrated resource plan of each load-serving entity required in Ordering Paragraph 1 shall take into account the greenhouse gas target adopted by the Commission in the prior year and shall propose any necessary procurement activities to commence with the approval of the plan and up to three years later, if requesting Commission approval of those procurement plans.

5. For purposes of integrated resource planning, a disadvantaged community shall be defined as any community statewide scoring in the top 25 percent using the most recent version of the California Environmental Protection Agency's CalEnviroScreen tool.

6. The integrated resource plan of each load-serving entity (LSE) required in Ordering Paragraph 1 shall include the following information related to disadvantaged communities:

- A description of which disadvantaged communities, if any, the LSE serves.
- What current and planned activities/programs of the LSE, if any, impact disadvantaged communities.
- A qualitative description of the demographics of the customers the LSE serves and how it is currently addressing or plans to comply with the requirement to minimize air pollutants.
- Detailed estimates of emission of annual greenhouse gases and local air pollutants (including at least, nitrogen oxides and particulate matter), as well as annual starts of natural gas plants. These emissions estimates shall include emissions due to cycling as well as normal operations.
- Locational information for all planned resources if proposed to be located in a disadvantaged community, including both emitting and non-emitting resources.
- Planned activities to conduct outreach and seek input from any disadvantaged communities that could be impacted by any procurement activities.

- A summary of issues raised by residents or organizations representing disadvantaged communities during outreach activities.
- A description of evaluation criteria that will be used to evaluate procurement of generation or storage resources located in disadvantaged communities, including any scoring bonuses or other approaches to ensuring early priority on disadvantaged communities.

7. Any load serving entity proposing to develop new natural gas resources or re-contract with existing natural gas resources in their integrated resource plans required by Ordering Paragraph 1 shall make a showing justifying why another lower-emitting resource could not meet the need identified.

8. The reference system portfolio represented by the total resources in Figure 3 of this decision and the incremental resources in Figure 6 of this decision are hereby adopted as the optimal portfolio required by Section 454.51, for use as a guide for individual load-serving entity portfolios and development of integrated resource plans.

9. The integrated resource plans filed in response to Ordering Paragraph 1 of this decision shall include all statutory requirements in addition to those in Public Utilities Code Sections 454.51 and 454.52, including but not limited to, requirements associated with energy efficiency, demand response, the renewables portfolio standard, energy storage, and resource adequacy.

10. The Commission forwards the 2030 portfolio associated with the Default Scenario modeled by staff as part of the Reference System Plan and the 2030 portfolio associated with the 42 Million Metric Ton Scenario to the California Independent System Operator, for use in its 2018-19 Transmission Planning Process, as the reliability base case and the policy-driven case, respectively.

11. All load serving entities with annual load forecasts that exceed 700 gigawatt hours on a rolling three-year average basis, except PacifiCorp, shall be required to file Standard Plans utilizing the template in Attachment A of this decision.

12. All load serving entities with annual load forecasts that are 700 gigawatt hours or less on a rolling three-year average basis, except PacifiCorp, shall be required to file Alternative Plans consisting of at least the following information:

- California Energy Commission (CEC) Form S1
- CEC Form S2 or Energy Information Administration (EIA) Form 861 or EIA Form 861S
- CEC Power Content Report
- A description of the treatment of disadvantaged communities, as required in Ordering Paragraph 6 above.

13. PacifiCorp shall file an Alternative integrated resource plan (IRP) consisting of any IRP submitted to another public regulatory entity within the previous calendar year, and shall also include the information required in Ordering Paragraph 6 of this decision.

14. Commission staff shall continue the informal Modeling Advisory Group activities in this proceeding and shall utilize the Strategic Energy Risk Valuation Model in preparation for aggregating individual integrated resource plans to form a Preferred System Plan to be considered by the Commission. Parties will be given an opportunity to comment on the production cost modeling approach and results on the record of this proceeding.

15. Any parties conducting production cost modeling for use in this proceeding shall follow the guidance outlined in Attachment B of this decision.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall establish integrated resource planning costs memorandum accounts by submitting Tier 2 advice letters within 30 days of the date of this decision. Costs recorded in these accounts shall not exceed \$18 million total across all three utilities, and the costs shall be allocated on the basis of proportion of projected 2030 load share.

17. The Commission's Executive Director shall hire and manage one or more contractors to perform tasks in support of the integrated resource planning process ordered in this decision. The costs of such tasks shall not exceed \$3 million per year for six years, or a total of \$18 million, with costs eligible to be rolled over annually until no later than 2030.

18. The Commission delegates to the Assigned Commissioner and/or assigned Administrative Law Judge the authority to modify the required filing date identified in Ordering Paragraph 1 for the integrated resource plan filings of individual load-serving entities.

This order is effective today.

Dated \_\_\_\_\_, at San Francisco, California.



# ATTACHMENT A

## Standard LSE Plan

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NAME OF FILING ENTITY

2018 INTEGRATED RESOURCE PLAN

DATE

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**How to use this template:**

- *Instructions are provided in italics under each section. Delete all instructions before submitting the form, but preserve the numbered section headings.*
- *Complete each section. If the section is not applicable to the LSE, simply indicate “Not applicable” and provide a brief explanation.*
- *Definitions are provided in the Glossary of Terms at the end of this template.*

**1. Executive Summary**

*Use this section to provide an overview of the process used by the LSE to develop its plan and summarize the LSE’s findings, including a brief overview of the LSE’s Preferred Portfolio and Action Plan.*

**2. Study Design**

*Use this section to describe how the LSE approached the process of developing its LSE Plan.*

**Load Assignments for Each LSE**

*For projecting load across the IRP Planning Horizon (i.e., until 2030, for the purposes of IRP 2017-18), LSEs shall use the mid AAEE version of Form 1.1c of the 2017 IEPR Mid demand case. An ESP may re-purpose its load forecast previously filed with the Commission (e.g., in the RPS or RA proceeding), provided the load forecast is consistent with the one submitted by the ESP to the CEC in its 2017 IEPR Confidential Form 7.1 (Loads and Resources under Contract). ESP load forecasts should be filed under seal, and the Commission staff will aggregate the ESP submittals to protect confidentiality.*

*If necessary to project load beyond the final year of the IEPR planning horizon (e.g., from 2027 to 2030), LSEs shall use a compound annual rate of growth calculated over the last five years of the IEPR forecast years.*

**Required and Optional Portfolios**

*Each LSE must produce at least one portfolio, deemed the “Conforming Portfolio,” that uses the assigned load forecast and is demonstrated to be consistent with the Reference System Portfolio according to the following criteria:*

- *Use of either the GHG Planning Prices in Table A or the LSE-Specific 2030 GHG Emissions Benchmark in Table B*
- *Use of input assumptions matching those used in developing the Reference System Portfolio, with the following exceptions based on updated information:*
  - *LSEs shall use the load assignment indicated above, namely the mid AAEE version of Form 1.1c of the 2017 IEPR Mid demand case.*

- LSE load modifier assumptions shall be consistent with the 2017 IEPR mid case projections of both PV and non-PV self-generation, and load-modifying demand response.
- LSEs shall use the 2017 IEPR burner-tip natural gas price projections.

LSEs may also study and report “Alternative Portfolios” developed from additional scenarios using different assumptions (including differing load and load modifier assumptions) from the Reference System Plan. For example, an IOU may choose to prepare a portfolio that plans for CCA load departure not reflected in its assigned IEPR load forecast. IOUs doing so shall use binding Notices of Intent provided by CCAs consistent with Commission direction in D.14-02-040, and they shall adjust their 2030 GHG Emissions Benchmark (if applicable; refer to Table B below) downward proportionally with the departing load.

For all Alternative Portfolios developed, any deviations from the Conforming Portfolio must be explained and justified. If the LSE uses different load and load modifier assumptions as part of any Alternate Portfolios, the LSE should report that information using the standard IEPR filing form templates associated with that information, as described in detail in Section 5: Data. The LSE must document and explain differences from what the LSE filed with the CEC in 2017 for its 2017 IEPR process.

Among the Conforming Portfolio and Alternative Portfolio(s) developed by the LSE, the LSE will identify one as its “Preferred Portfolio.”

#### **GHG Planning Price**

LSEs electing to use the GHG Planning Price—rather than the LSE-specific GHG Emissions Benchmark—in developing their portfolio(s) must use the values presented in Table A below. The GHG Planning Price is equivalent to the marginal cost of GHG abatement associated with the 42 MMT Scenario for the years 2018 to 2026 (i.e., a curve that slopes upward from ~\$15/ton to ~\$23/ton), followed by a straight-line increase from ~\$23/ton in 2026 to \$150/ton in 2030. The straight-line increase is intended to fill the gap for the years for which RESOLVE does not produce GHG abatement cost values (i.e., 2027, 2028, and 2029).

**TABLE A**

<b>GHG Planning Price (\$ per metric ton of CO<sub>2</sub>e) for use in IRP</b>	
2018	\$15.17
2019	\$16.05
2020	\$16.94
2021	\$17.88
2022	\$18.86
2023	\$19.91
2024	\$21.02
2025	\$22.19
2026	\$23.44
2027	\$55.08
2028	\$86.72

2029	\$118.36
2030	\$150.00

### **GHG Emissions Benchmark**

*LSEs electing to use the LSE-specific GHG Emissions Benchmark—rather than the GHG Planning Price—in developing their portfolio(s) must use the 2030 value presented in Table B below.*

*If the total emissions attributable to the LSE’s Preferred Portfolio exceed its GHG Emissions Benchmark for 2030, the LSE must explain the difference and describe additional measures it would take over the following 1-3 years to close the gap, along with the estimated cost of those measures.*

*Each ESP is required to calculate its own confidential GHG Emissions Benchmark based on its 2030 load share within the host EDU’s territory. For example, if an ESP’s 2030 load comprises 10% of the total direct access load within PG&E’s territory, its benchmark would be approximately 0.159 MMT.*

*For ESPs that serve load in more than one IOU service territory, those ESPs should add up the separate GHG Emissions Benchmarks calculated based on its share of direct access load for each IOU service territory to result in a single benchmark.*

**TABLE B**

<b>LSE</b>	<b>2030 GHG Emissions Benchmark (MMT)*</b>
<i>Golden State Water Company (Bear Valley Electric Service)</i>	<i>0.028</i>
<i>Liberty Utilities (CalPeco Electric) LLC</i>	<i>0.121</i>
<i>Pacific Gas and Electric Company (Bundled)</i>	<i>13.21</i>
<i>Direct Access (ESPs) within Pacific Gas and Electric Company</i>	<i>1.590</i>
<i>Marin Clean Energy CCA</i>	<i>0.326</i>
<i>Sonoma Clean Power CCA</i>	<i>0.305</i>
<i>PacifiCorp</i>	<i>0.355</i>
<i>Southern California Edison Company (Bundled)</i>	<i>13.037</i>
<i>Direct Access (ESPs) within Southern California Edison Company</i>	<i>1.964</i>
<i>Lancaster Choice Energy CCA</i>	<i>0.105</i>
<i>San Diego Gas and Electric Company (Bundled)</i>	<i>3.480</i>
<i>Direct Access (ESPs) within San Diego Gas and Electric Company</i>	<i>0.719</i>

*\*To determine these values, first the recommended 2030 GHG planning target for the electric sector was divided among Commission jurisdictional electric distribution utilities (EDUs) based on CARB’s draft methodology for the 2021-2030 allowance allocation under the Cap and Trade program. That value was then proportionally allocated among the host EDU and non-EDUs (CCAs and ESPs) within the host EDU’s territory based on their projected 2030 load shares. To estimate 2030 load shares for each LSE, a compound annual growth rate was applied based on the last five years of the IEPR 2016–2026 Mid Demand Baseline Case with no AAEE Savings, as done on a system-wide basis in RESOLVE.*

**GHG Accounting in IRP Planning**

**Clean Net Short (CNS) method.** This method apportions GHG emissions associated with the system's dispatchable fossil generation to each LSE based on how it plans to rely on unspecified power from CAISO system. This approach is based in part on the method described in PG&E's comments submitted to the CEC on the "Assembly Bill 1110 Implementation Proposal for Power Source Disclosure." It involves the following steps:

1. The LSE will subtract out any owned or contracted non-dispatchable GHG-emitting resources (such as non-dispatchable CHP or fossil imports) it plans to use to serve its hourly load from its projected hourly electricity demand.
2. The LSE will subtract its owned or contracted (either current or planned) GHG-free generation from the projected hourly electricity demand, less the amount subtracted in the previous step, deriving a "clean net short" (CNS).
  - a. GHG-free resources: RPS Bucket 1, hydroelectric, and nuclear generation, if delivered to a California balancing authority area.
  - b. GHG-emitting resources: any resources other than those deemed GHG-free above, including resources otherwise GHG-free but which are not delivered to a California balancing authority area.
3. The CNS will then be multiplied by the system emissions on an hourly basis, yielding total emissions associated with using unspecified system power for that LSE for every hour of 2030.
4. Finally, the emissions from all owned or contracted non-dispatchable GHG-emitting resources used to serve hourly load in step #1 will be computed using plant-specific emissions factors and added to the emissions from unspecified system power calculated in step #3.

For example, an LSE may anticipate 100 MW of load in a given hour in 2030. If the LSE's owned and contracted resources produce 75 MW of GHG-free generation and 5 MW of nondispatchable CHP in that hour, then the LSE's CNS is 20 MW for that hour. Assuming that the average emissions intensity of fossil generation on the CAISO system is estimated to be 0.5 tons/MWh for that hour. The LSE would multiply its CNS (20 MW) by the emissions intensity (0.5 tons/MWh) to yield 10 tons of CO<sub>2</sub>e for that hour of unspecified CAISO system power. The LSE would then add the emissions associated with the 5 MW of nondispatchable CHP to its total.

LSEs have two options for sourcing the hourly system emissions values used in step 3 when estimating the GHG emissions of their IRP portfolios:

1. **Production cost simulation.**

The LSE may use production cost simulation to determine the plants contributing to GHG emissions in all hours in which the LSE intends to rely on system power. The plant-specific emissions factors may be used to calculate the average emissions rates in each hour.

**2. Standard Values Based on the Reference System Portfolio**

*Commission staff will estimate the average emissions intensity (tons/MWh) of fossil generation on the CAISO system associated with the Reference System Portfolio on an hourly (8760) basis in the year 2030. Commission staff will provide a table of these emission intensity values to all LSEs in early 2018.*

**a. Objectives**

*Provide a description of the LSE's objectives for the analytical work it is documenting in the IRP.*

**b. Methodology****i. Modeling Tool(s)**

*Name all modeling software used by LSE to develop its IRP, if any, and include the vendor and version number. Provide an explanation of differences between the LSE's modeling tool and RESOLVE, and an explanation of how those differences should be considered during evaluation of the LSE's portfolio(s).*

**ii. Modeling Approach**

*Describe the LSE's overall approach to developing the scenarios it evaluated, and explain why each scenario was considered. Also describe any calculations, including post-processing calculations, used to generate metrics for portfolio analysis.*

**iii. Assumptions**

*Describe any inputs or assumptions used by the LSE that differ from the corresponding assumption used by the Commission to prepare the Reference System Plan. Each differing assumption must include a rationale for use of this assumption and any intermediate calculations used to develop the assumption and source data with citations. Include a side-by-side comparison of the original assumption data from the Reference System Plan and the LSE's differing assumption data. Report data according to the requirements in the Data section below.*

### 3. Study Results

*Use this section to present the results of the analytical work described in Section 2: Study Design.*

#### a. Portfolio Results

*Provide a list of all portfolios developed. Each portfolio's content must be itemized in the Data Template Excel workbooks referenced below. A portfolio clearly identifies:*

- *New resources that the LSE plans to invest in.*
- *Existing resources that the LSE owns or contracts with (includes projects not yet online but with a contract).*

*Each LSE must produce a Conforming Portfolio. Alternative Portfolios are also permitted, provided that any deviations from the Conforming Portfolio are explained and justified. The LSE will identify one portfolio as its Preferred Portfolio.*

#### b. Preferred Portfolio

*Describe the portfolio the LSE prefers to use for planning purposes and for which LSE seeks Commission approval or certification. Explain the reasons for the LSE's preference and how its Preferred Plan is consistent with each relevant statutory and administrative requirement (refer to PU Code Section 454.52(a)(1)). In providing its rationale, the LSE should assume that other LSEs procure in a manner consistent with the Reference System Plan.*

##### i. Local Air Pollutant Minimization

*Describe and provide quantitative evidence to support how the LSE's Preferred Portfolio minimizes localized air pollutants and other GHG emissions with early priority on disadvantaged communities.*

*In order to identify "disadvantaged communities" that are located within its service territory, each LSE must use CalEnviroScreen 3.0 to identify the top 25% of impacted census tracts on a statewide basis. LSEs must specify:*

- *Customers served in disadvantaged communities along with total disadvantaged population number served as a percentage of total number of customers served*
- *What current and planned LSE activities/programs, if any, impact disadvantaged communities or contribute to economic development within disadvantaged communities (e.g. list all individual programs carried out in/for disadvantaged communities, along with description of program)*



**ii. Cost and Rate Analysis**

*Describe and provide quantitative information to reflect how the LSE anticipates that its Preferred Portfolio will affect the costs for its customers. For this analysis, assume other LSEs procure resources in a manner consistent with the Reference System Plan.*

**IOU Requirements**

*Data must be provided showing the forecasted revenue requirement and system average rate for bundled customers for all portfolios developed by the IOU. The costs should be forecasted consistently with the categories covered by each IOU in its general rate case. The data should reflect the LSE's assigned load forecast, and revenue requirements for each portfolio should be broken down by the following categories:*

- *Transmission*
- *Distribution*
- *DSM Programs*
- *Generation*
- *Other*

*In presenting revenue requirement data, IOUs should clearly distinguish between current (baseline) projected revenue requirement broken down by the categories above, and the incremental projected revenue requirement broken down by the same categories, for each new resource portfolio that the IOU is showing results for in its Plan. IOUs should assume no procurement on behalf of non-bundled customers would be needed unless specifically required by the Commission.*

**All LSEs**

*In addition to the above specifications for the IOUs, all LSEs should consider cost and rate impacts on their customers when planning and submitting their individual IRPs, and, at a minimum, include a narrative description of their approach in support of this requirement.*

*Additionally, LSE Plans should account for any resources subject to the cost allocation mechanism (CAM) in their portfolios. LSEs should not make assumptions or predictions on what resources may be subject to the CAM in the future.*

**c. Deviations from Current Resource Plans**

*Describe and quantify any differences in the quantities and/or budgets for procurement between the LSE's Preferred Plan and any currently filed or authorized resource plans, including, but not limited*

*to: Bundled Plans, RPS Plans, Energy Efficiency Business Plans, Distributed Resource Plans, and specific procurement-related applications.*

**d. Local Needs Analysis**

*LSEs that serve load within a CAISO-defined local capacity area must report the LSE's own assessment of how it will meet the local capacity needs projected in the most recent CAISO Transmission Plan.<sup>1</sup>*

**4. Action Plan**

*This section will present all the actions that the LSE proposes to take in the next 1-3 years to implement its LSE Plan.*

**a. Proposed Activities**

*Describe any near-term activities the LSE proposes to undertake across resource types in order to implement its LSE Plan. Clearly describe how each activity relates to the study results presented in Section 3: Study Results.*

**b. Barrier Analysis**

- a. Identify any market, regulatory, financial, or other barriers or risks associated with the LSE acquiring the resources identified in the Preferred Portfolio. Include an analysis of any risks associated with potential retirement of existing resources on which the LSE intends to rely in the future.*

**c. Proposed Commission Direction**

*If applicable, describe any direction that the LSE seeks from the Commission, including any new spending authorizations, changes to existing authorizations, or changes to existing programmatic goals or budgets. Clearly relate any requested direction to the study results, proposed activities, and barrier analysis presented above.*

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<sup>1</sup> CAISO has ten primary local capacity areas (i.e. transmission-constrained load pockets): Humboldt, North Coast North Bay, Sierra, Stockton, Greater Bay, Greater Fresno, Kern, LA Basin, Big Creek Ventura, San Diego Imperial Valley.

## 5. Data

*LSE IRP Plans require reporting of various data types. Baseline resource portfolio data shall be reported in the “Baseline Resource Data Template” provided by the Commission.<sup>2</sup> New resource portfolio data shall be reported in the “New Resource Data Template” provided by the Commission.<sup>3</sup> Other data that is not asked for in these templates but is asked for in the reporting requirements described in the preceding sections shall follow the guidelines below in section 5.3.*

### a. Baseline Resource Data Template

*Follow the instructions within the template to report all resources under obligation to serve LSE load whether through an existing contractual or ownership relationship. This includes both online units with a CAISO Resource ID, as well as projects that are not yet online but have secured a contract and may therefore be identified in the Commission’s RPS Contracts Database or an Application filed at the Commission.*

*This template also asks for existing fixed cost and revenue requirement projections, if applicable to the reporting entity.*

*Save the file in the format of “Data\_LSEname\_BaseRsrc\_yyyymmdd.xlsx” where the field “LSEname” is replaced with the LSE name (e.g. “MCE” or “PGE”) and “yyymmdd” is replaced with the date the file is submitted to the Commission. Spaces are not allowed in the file name. Special characters are not allowed, except for underscore (“\_”) and dash (“-”).*

### b. New Resource Data Template

*For EACH portfolio considered by the LSE (e.g. Conforming, Alternate1, Alternate2) follow the instructions within the template to report new resources, including the projected total fixed costs of these new resources, that the LSE plans to invest in to serve its load over the IRP planning horizon. The fixed cost reporting includes any new transmission triggered by the new resources and the LSE’s share of those costs. IOUs shall also include a projection of the incremental revenue requirement (i.e., incremental to what is reported in the Baseline Resource Data Template). New resources are analogous to “candidate” resources as defined in the RESOLVE model. To the extent possible, each resource should be mapped to a RESOLVE candidate resource type. If the LSE’s selected new resource does not match with any pre-defined RESOLVE candidate resource type, it may select “Other\_New” and provide a description.*

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<sup>2</sup> Available at: <http://www.cpuc.ca.gov/irp/filingtemplates/>.

<sup>3</sup> Available at: <http://www.cpuc.ca.gov/irp/filingtemplates/>.

*Note that the Conforming Portfolio will be based on the load assignments and the 2017 IEPR demand forecast as specified earlier in this template. If an LSE proposes no changes to this load and load modifier assumption as part of its LSE Plan, then no load information must be reported. If LSEs use different load and load modifier assumptions as part of any Alternate Portfolios, the LSE should report that information using the standard IEPR filing form templates associated with that information, included as tabs within the New Resource Data Template. The LSE should clearly identify the data that differs from the forms it submitted to the CEC in 2017 as part of the 2017 IEPR process. The table below indicates which standard IEPR filing forms apply to which entity.*

<b>Form #</b>	<b>Form Description</b>	<b>IOU</b>	<b>CCA</b>	<b>ESP</b>
Form 1.1a	RETAIL SALES OF ELECTRICITY BY CLASS OR SECTOR (GWh) Bundled & Direct Access	X		
Form 1.1b	RETAIL SALES OF ELECTRICITY BY CLASS OR SECTOR (GWh) Bundled Customers	X		
Form 1.2	DISTRIBUTION AREA NET ELECTRICITY FOR GENERATION LOAD (GWh)	X		
Form 1.3	LSE COINCIDENT PEAK DEMAND BY SECTOR (Bundled Customers)	X		
Form 1.4	DISTRIBUTION AREA COINCIDENT PEAK DEMAND	X		
Form 3.2	ENERGY EFFICIENCY - CUMULATIVE INCREMENTAL IMPACTS	X		
Form 3.3	DISTRIBUTED GENERATION - CUMULATIVE INCREMENTAL IMPACTS	X		
Form 3.4	DEMAND RESPONSE - CUMULATIVE INCREMENTAL IMPACTS	X		
Form 4	REPORT ON FORECAST METHODS AND MODELS	X	X	
Form 6	UNCOMMITTED DEMAND-SIDE PROGRAM METHODOLOGY	X		
Form 7.1	ESP DEMAND FORECAST			X
Form 7.2	CCA DEMAND FORECAST		X	

*Each LSE should save a separate file for each portfolio in the format of "Data\_LSEname\_NewRsrc\_Identifier\_yyyymmdd.xlsx" where the field "LSEname" is replaced with the LSE name (e.g. "MCE" or "PGE"), the field "Identifier" is replaced with Conforming, TE, Alternate1, Alternate2, etc, and "yyymmdd" is replaced with the date the file is submitted to the Commission. Spaces are not allowed in the file name. Special characters are not allowed, except for underscore ("\_") and dash ("-").*

**c. Other Data Reporting Guidelines**

*The LSE may need to report supplemental or supporting data that is not asked for in the Data Templates described above, but is asked for within the Standard LSE Plan Template instruction above. LSEs should report the data in one or more Excel-compatible workbooks.*

*Save a separate file for each portfolio in the format of*

*“Supporting\_LSEname\_Identifier\_yyyymmdd.xlsx” where the field “LSEname” is replaced with the LSE name (e.g. “MCE” or “PGE”), the field “Identifier” is replaced with Conforming, Alternate1, Alternate2, etc, and “yyymmdd” is replaced with the date the file is submitted to the Commission. Spaces are not allowed in the file name. Special characters are not allowed, except for underscore (“\_”) and dash (“-”).*

**6. Lessons Learned**

*Document any suggested changes to the IRP process for consideration by the Commission. Explain how the change would facilitate the ability of the Commission and LSEs to achieve state policy goals.*

## ***Glossary of Terms***

**Alternative Portfolio** – LSEs are permitted to submit “Alternative Portfolios” developed from scenarios using different assumptions from those used in the Reference System Plan. Any deviations from the Conforming Portfolio must be explained and justified.

**Clean Net Short (CNS)** – In accounting for GHG emissions in its LSE Plan, the LSE will subtract its owned or contracted GHG-free generation directly from its projected hourly electricity demand, estimating the remaining MW of GHG-emitting resources it plans to use to serve its load on an hourly basis. Then the LSE will subtract out any owned or contracted GHG-emitting resources (such as non-dispatchable CHP or fossil imports) it plans to use to serve its hourly load, deriving a “clean net short.”

**Conforming Portfolio** – Each LSE must produce a “Conforming Portfolio” that is demonstrated to be consistent with the Reference System Portfolio according to the following criteria: (1) use of either the GHG Planning Prices or the LSE-Specific 2030 GHG Emissions Benchmark, and (2) use of input assumptions matching those used in developing the Reference System Portfolio

**Data Template** – Data provided by the LSE should be reported in the “Baseline Resource Data Template” and the “New Resource Data Template” provided by the Commission. “Baseline” means existing resources and costs, including resources already contracted but not yet online. “New” means any new (incremental to the baseline) resources and costs associated with a particular LSE portfolio.

**Disadvantaged Communities** – For the purposes of IRP, “disadvantaged communities” refer to the 25% highest scoring census tracts in the state using results of the California Communities Environmental Health Screening Tool, Version 3 (CalEnviroScreen 3.0), consistent with the California Environmental Protection Agency definition

**GHG Emissions Benchmark** – Each LSE filing a Standard LSE Plan must use either the GHG Emissions Benchmark or GHG Planning Price in developing its Conforming Portfolio. The LSE-specific benchmarks and calculation method are provided in Table B. If the total emissions attributable to the LSE’s preferred portfolio exceed its GHG Emissions Benchmark for 2030, the LSE must explain the difference and describe additional measures it would take over the following 1 - 3 years to close the gap, along with the cost of those measures.

**GHG Planning Price** – The GHG Planning Price is equivalent to the marginal cost of GHG abatement associated with the 42 MMT Scenario for the years 2018 to 2026 (i.e., a curve that slopes upward from ~\$15/ton to ~\$23/ton), followed by a straight-line increase from ~\$23/ton in 2026 to \$150/ton in 2030, as shown in Table A. Each LSE must use either the GHG Planning Price or GHG Emissions Benchmark in developing its Conforming Portfolio.

**IRP Planning Horizon** – The IRP Planning Horizon will typically cover 20 years. However, for the purposes of this IRP 2017-18 cycle, the IRP Planning Horizon will cover only up to the year 2030.

**Long term** – 10 or more years (unless otherwise specified)

**Portfolio** – A portfolio is a set of supply and/or demand resources with certain attributes that together serve a particular level of load.

**Preferred Portfolio** – Among all the portfolios developed by the LSE, the LSE will identify one as the most suitable to its own needs, deemed its “Preferred Portfolio.” Any deviations from the Conforming Portfolio must be justified and explained.

**Reference System Plan** – The Reference System Plan refers to the Commission-approved integrated resource plan that includes an optimal portfolio (Reference System Portfolio) of future resources for serving load in the CAISO balancing authority area and meeting multiple state goals, including meeting GHG reduction and reliability targets at least cost.

**Reference System Portfolio** – The Reference System Plan refers to the Commission-approved portfolio that is responsive to statutory requirements per Pub. Util. Code 454.51; it is part of the Reference System Plan.

**Scenario** – A scenario is a portfolio together with a set of assumptions about future conditions.

**Short term** – 1 to 3 years (unless otherwise specified)

**Standard LSE Plan** – A Standard LSE Plan is the type of integrated resource plan that an LSE is required to file if its assigned load forecast is  $\geq 700$  GWh in any of the first five years of the IRP planning horizon.

**Standard LSE Plan Template** – Each LSE required to file a Standard LSE Plan must use the Standard LSE Plan Template according to the instructions provided herein.

(End of Attachment A)

## **ATTACHMENT B**

### **Guide to Production Cost Modeling in the Integrated Resource Plan Proceeding**

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## I. Introduction

This document describes guidelines for production cost modeling in the Commission's Integrated Resource Plan (IRP) rulemaking (R.16-02-007), as well as a process for calibrating and vetting production cost modeling using the Reference System Plan and subsequently applying the calibrated and vetted production cost modeling to evaluate the Preferred System Plan being considered in IRP. This document describes a potentially durable modeling process that could be replicated in future IRP cycles, as well as some workarounds to make the process fit within the schedule of this first IRP cycle.

Production cost modeling may be employed by LSEs to inform development of their respective IRP filings (LSE Plans). LSEs should adhere to the production cost modeling guidelines specified in this document<sup>1</sup> to the extent possible and be consistent with the baseline assumptions in the "Unified RA/IRP Inputs and Assumptions" staff deliverable as described later in this document.

Production cost modeling will also be conducted by Commission staff to evaluate the Preferred System Plan. Parties to the IRP proceeding may wish to also conduct their own modeling to evaluate the Preferred System Plan. Production cost modeling for the purpose of evaluating the Preferred System Plan must undergo the calibrating and vetting process described in this document. The goal of calibrating and vetting is to ensure modeling conducted by different parties produces comparable results and that differences are understood. The Reference System Plan will be used as the basis for calibrating and vetting modeling. Completing the calibration and vetting work up front using the Reference System Plan enables subsequent modeling on the Preferred System Plan to focus more on evaluating the Preferred System Plan, rather than validating models or characterizing differences between models.

## II. Production Cost Modeling Calibration and Vetting

This section describes a process for calibrating and vetting production cost modeling in preparation for relying on such modeling to evaluate the Preferred System Plan. The process will be led by Commission staff via the Modeling Advisory Group,<sup>2</sup> a forum conducive to collaborative work between multiple

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<sup>1</sup> The calibration and vetting process described in this document may ultimately result in revisions to the production cost modeling guidelines. Nevertheless, LSEs who will use production cost modeling to develop their respective LSE Plans should use the guidelines in this document since the work to develop an LSE Plan occurs in parallel to the calibration and vetting process. Any guideline revisions at the completion of the calibration and vetting process would apply to the subsequent evaluation of the Preferred System Plan, which is the aggregation of LSE Plans.

<sup>2</sup> Modeling Advisory Group (MAG) notices are emailed to the proceeding service list – there is no separate list. Previous meetings and materials are posted here: <http://www.cpuc.ca.gov/General.aspx?id=6442453968>.

parties and staff. The process will include an opportunity for parties to formally comment on the modeling work on the IRP proceeding record, and conclude with the Commission providing revised guidance to standardize modeling across multiple parties in preparation for modeling to evaluate the Preferred System Plan. The following table summarizes the timeline of this process.

Item	Date	Activity or Milestone
(1)	December 2017 – February 2018	Staff calibrate RESOLVE and SERVM model input data with Reference System Plan and 2017 IEPR demand forecast
(2)	February 9, 2018	Staff posts SERVM model input data and documentation
(3)	January – April 2018	Staff hosts monthly Modeling Advisory Group meetings
(4)	February – April 2018	Staff and modeling parties conduct modeling based on (2)
(5)	April 9, 2018	Staff and modeling parties share results and revise as needed
(6)	April 23, 2018	Parties formally comment
(7)	May 2018	Commission, via ALJ ruling, provides revised guidance, if needed

Commission staff will use the SERVM<sup>3</sup> production cost model to measure operational performance and verify satisfaction of the Planning Reserve Margin<sup>4</sup> (PRM) requirement. This is the same model as used in the Resource Adequacy proceeding to calculate Effective Load Carrying Capability (ELCC).<sup>5</sup> Other parties who wish to evaluate the Preferred System Plan with their own production cost modeling should participate in the Modeling Advisory Group calibration and vetting process introduced above. Parties may use a production cost modeling tool of their choosing, but are expected to use the guidance within this document, use the input data and documentation posted by staff in early February 2018, provide modeling results in early-April 2018, and collaborate with staff and other parties to align modeling to the extent possible. The items listed in the table above are described below in further detail.

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<sup>3</sup> Strategic Energy Risk Valuation Model – developed by and commercially licensed through Astrape Consulting.

<sup>4</sup> Refers to the system Resource Adequacy requirement based on each LSE's peak demand forecast plus a 15% planning reserve margin. See: <http://www.cpuc.ca.gov/General.aspx?id=6307>.

<sup>5</sup> The Resource Adequacy proceeding adopted ELCC values in D.17-06-027. The record of this proceeding includes proposals providing relevant background information on modeling and ELCC studies.

**(1) Staff calibrate RESOLVE and SERVVM model input data with Reference System Plan and 2017 IEPR demand forecast**

The purpose of this step is to develop a production cost modeling input dataset consistent with both the 2017 IEPR demand forecast and the RESOLVE model's 42 MMT core policy case (which is the chosen Reference System Plan portfolio). Commission staff will develop this dataset as follows:

- a. Update the RESOLVE model with the 2017 IEPR demand forecast and associated load modifier components and rerun the 42 MMT core policy case.
- b. Build a SERVVM model input dataset from this 2017 IEPR-updated 42 MMT core policy case.

Having a 2017 IEPR updated production cost modeling dataset facilitates subsequent evaluation of and consistency with the Preferred System Plan which would have been aggregated from individual LSE Plans that also used the 2017 IEPR. Rerunning the RESOLVE model's 42 MMT core policy case with 2017 IEPR data allows RESOLVE operational results to be comparable to production cost models built with 2017 IEPR data and eliminates a need to do any production cost modeling with 2016 IEPR data.<sup>6</sup> The updated RESOLVE 42 MMT core policy case built with the 2017 IEPR is intended solely for the exercise of calibrating and vetting production cost models and does not replace the Commission adopted Reference System Plan and portfolio.

**(2) Staff posts SERVVM model input data and documentation**

This will be a key deliverable from Commission staff to parties. It will illustrate a translation of RESOLVE model aggregate data into SERVVM model unit-level data. It will include baseline unit-level detail for most of the Western Interconnect. If using production cost modeling for individual LSE Plan development, the LSE's modeling should be consistent with the baseline assumptions provided in this deliverable. If using production cost modeling to evaluate the Preferred System Plan, parties must use this deliverable as input for its modeling within the Modeling Advisory Group calibration and vetting process. The deliverable will contain two components:

- a. 2018 Unified RA/IRP Inputs and Assumptions document – description of zonal and unit level input data for the SERVVM model as used in the Resource Adequacy proceeding (study year 2019) and the IRP proceeding (study years 2022, 2026, and 2030). This document will also include incremental modeling guidance necessary for network reliability models (e.g. "power flow" modeling).
- b. Data workbooks – SERVVM model input data in a generic spreadsheet format such that it can be imported into any production cost model, and other assumptions relevant to network reliability modeling such as resource locations by transmission busbar.

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<sup>6</sup> The original RESOLVE 42 MMT core policy case was built with the 2016 IEPR demand forecast.

This deliverable is intended to replace the function of the traditional “Assumptions and Scenarios” document that has been annually created to inform the Commission’s Long Term Procurement Plan proceeding and the CAISO’s Transmission Planning Process (TPP).

**(3) Staff hosts monthly Modeling Advisory Group meetings**

Commission staff expects to hold monthly (or as needed) Modeling Advisory Group meetings to facilitate the calibration and vetting process. The meeting format may be webinar, teleconference, or in-person. Staff and parties should provide updates on modeling progress and discuss any modeling issues that arise.

**(4) Staff and modeling parties conduct modeling based on (2)**

Commission staff and parties develop and run their respective production cost models and report progress and issues in Modeling Advisory Group meetings. Further details on specific production cost modeling steps and modeling conventions are provided in the following sections of this document.

**(5) Staff and modeling parties share results and revise as needed**

Commission staff and parties share their respective production cost model results and collaboratively assess differences. Additional runs may be necessary to better align results. In terms of metrics for comparison between models, staff and other parties should follow the guidelines in the ALJ Ruling Directing Production Cost Modeling Requirements<sup>7</sup> issued in this proceeding on September 23, 2016, unless superseded by a specific guideline called out in this document or a recommendation agreed upon in the Modeling Advisory Group.

**(6) Parties formally comment**

The Commission will provide an opportunity for parties to formally comment on the production cost modeling calibration and vetting results on the IRP proceeding record.

**(7) Commission provides revised guidance**

The Commission will provide revised guidance in the form of an Administrative Law Judge ruling, considering the recommendations of the Modeling Advisory Group and party comments, to standardize production cost modeling across multiple parties to the greatest extent possible. Parties will be expected to follow this guidance when they conduct their own production cost modeling or related analysis to evaluate the Preferred System Plan.

### **III. Modeling Scope and Conventions**

The following describes the scope and conventions that Commission staff and parties are expected to use for both the production cost modeling calibration and vetting process and the subsequent evaluation of the Preferred System Plan. As indicated above, at the end of the calibration and vetting process the Commission may revise this guidance. Also as indicated above, LSEs using production cost modeling to inform their individual LSE Plan development should adhere to the modeling guidelines specified here to the extent possible.

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<sup>7</sup> <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451199>.

- A. Study years: 2022, 2026, and 2030.
- B. SERVVM will be run using hourly time-steps.
- C. Hourly system load shapes will be built up from fundamental consumption load shapes and shapes for various load modifiers such as AAEE, TOU rates, and EV charging patterns.  
Transmission and distribution loss effects will be accounted for.
- D. BTM PV will be explicitly modeled as generation, rather than embedded in the load forecast.  
Transmission and distribution loss effects will be accounted for.
- E. Loss-of-load event definitions and counting conventions, and operating reserve targets<sup>8</sup> shall be consistent with those used in the Resource Adequacy proceeding's production cost modeling with SERVVM for ELCC calculations. Multiple loss-of-load events occurring within one day shall count as one event for purposes of counting events towards a reliability target. The loss-of-load event occurs when regulation up/down (1.5% of hourly forecast load) or spinning reserves (3.0% of hourly forecast load) cannot be maintained.
- F. Average portfolio ELCC values will be calculated for each month of the study year, consistent with the monthly Resource Adequacy program.
- G. The loss-of-load-expectation (LOLE) reliability target range for calculating monthly average portfolio ELCC values shall be the range 0.02 to 0.03 LOLE for each month, same as was used in the Resource Adequacy proceeding's production cost modeling with SERVVM.<sup>9</sup>
- H. For ELCC calculations, the calibration of the system under study to the LOLE reliability target range may involve removing or adding generation.
  - Removal of generation to surface LOLE events in overbuilt systems shall be according to the following order:<sup>10</sup> Conventional thermal generators that have announced their retirement will be removed first. If LOLE remains below the target level, additional conventional thermal generation will be removed from CAISO areas ranked by age of the facility. The oldest one will be removed first, continuing in order of age. No hydro generation or renewable generation will be removed.
  - Addition of generation to reduce LOLE events in underbuilt systems shall use perfect capacity as additions. Perfect capacity is a modeling proxy for generation with no

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<sup>8</sup> As a percent of hourly forecast load, regulation up/down is 1.5% each, load following up is 2.5%, load following down is 1.5%, spinning reserves is 3.0%, non-spinning reserves is 3.0%.

<sup>9</sup> Specifically, the monthly LOLE target was created by first taking the industry standard 0.1 LOLE annual target and assuming that most of those events map to the four peak months of June through September, or one third of the year. Assuming a similar target reliability for the rest of the year would mean that total LOLE over the entire year should have a target of  $0.1 \times 3 = 0.3$ . Thus, monthly LOLE studies would have a monthly target LOLE of  $0.3/12 = 0.025$ , i.e. a target range of 0.02 to 0.03.

<sup>10</sup> Note that the order specified here is simply a modeling convention picking one systematic way to remove capacity for the sole purpose of calibrating a system to a target reliability level in order to perform ELCC calculations. The choice and order of removing units does not imply the units are likely to retire or should retire.

operating constraints, e.g. always available, starts instantly, infinite ramp rate, no minimum operating level.

- Although the calibration step alters the system under study, this is a typical way of performing ELCC calculations and is not expected to significantly affect the ELCC measurement.
- I. Average portfolio ELCC calculations will include all wind and utility-scale solar, both existing and new, but exclude all BTM PV. The calculation will treat all of these resources as if they were fully deliverable.
- J. Reserve margin calculations will be performed for each month of a study year, relying on the average portfolio ELCC calculations as stated above. The conventions in the following table apply:

Component	Counting convention
Peak demand	IEPR 1-in-2 monthly peak consumption forecast adjusted for load-modifier impacts including BTM PV impact
Existing non-wind, non-solar	Use current monthly Net Qualifying Capacity values
New non-wind, non-solar	Use same conventions as the RESOLVE model
Wind and solar (excluding BTM PV), existing and new	Monthly average portfolio ELCC of these resources combined. Discount this value by the ratio of fully-deliverable capacity to total capacity.

- K. Reporting of operational performance will include at least: LOLE probabilistic reliability level, emissions,<sup>11</sup> including estimating emissions from starts and stops, and NOx and PM2.5, RPS generation, curtailment patterns, production cost, import/export flows, and frequency of load following reserve shortages.

#### IV. Modeling Steps

The following describes the steps that Commission staff will use for the production cost modeling calibration and vetting process. In the steps below, “study” or “studies” means production cost modeling runs. Parties participating in the calibration and vetting process with their own production cost model are expected to perform the “as found” study, but are not expected to perform any ELCC or reserve margin calculations. For the purposes of calibrating and vetting different production cost modeling efforts, comparing results from “as found” studies should be sufficient. Staff will be performing the ELCC and reserve margin calculation steps to exercise its own modeling process in preparation for evaluating the Preferred System Plan.

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<sup>11</sup> The scope of emissions reporting at the system level will be CAISO balancing area, California, and WECC-wide. CAISO area and California GHG emissions accounting should align with Energy Commission and CAISO production cost modeling practices to the extent possible.

- A. Conduct “as found” annual studies for years 2022, 2026, and 2030
  1. Evaluate operational performance, including the metrics as described above
  2. Quantify in MW the amount of effective capacity that should be added or removed to achieve an annual 0.1 LOLE target
  3. Benchmark key metrics from SERVIM (or other production cost model) with equivalent metrics from the RESOLVE model’s 2017 IEPR-updated 42 MMT core policy case
- B. Calculate monthly average portfolio ELCC values for wind and utility solar
  1. For each month, calibrate the portfolio under study to the range of 0.02 to 0.03 LOLE for each month. Report the quantity of generation added or removed in MW.
  2. Calculate the monthly average portfolio ELCC of wind and utility solar together
- C. Calculate the monthly reserve margin and verify satisfaction of the PRM system reliability requirement in each month of the study year (relying on the ELCC values in step B.)

Note that the production cost modeling exercises above do not include any marginal ELCC calculations. For this IRP cycle, the Commission directs LSEs to use marginal ELCCs derived from the RESOLVE model’s Reference System Plan case and provided for reference in the table below. The Commission will consider providing production cost modeling-based marginal ELCCs in the subsequent IRP cycle.

ELCC Values	2018	2022	2026	2030
Marginal Solar ELCC (including BTM PV)	13%	2%	2%	2%
Marginal Wind ELCC	29%	31%	30%	30%

## V. Preferred System Plan Production Cost Modeling

This section describes production cost modeling steps that Commission staff will take to evaluate the Preferred System Plan. Staff will use the SERVIM production cost model to measure operational performance and verify satisfaction of the PRM requirement in each month of the study year, consistent with the current Resource Adequacy program. Staff will follow any new guidelines that resulted from the calibration and vetting process described above. Parties wishing to conduct their own production cost modeling to evaluate the Preferred System Plan are expected to do the same.

## VI. Modeling Steps

- A. Aggregate the individual LSE Plans into the Preferred System Plan SERVIM dataset
  1. The aggregation process must ensure that no resources are double-counted or under-counted, and that the aggregate of new resources selected by LSEs does not exceed the available resource potential. This step may require staff to make additional data requests to LSEs to resolve any issues.
  2. Staff posts the SERVIM model input data representing the Preferred System Plan. This is also a key deliverable from staff to parties and serves as the common input for any party



using production cost modeling to conduct their own evaluation of the Preferred System Plan, similar to the function and form of the SERVIM model input data that was provided by staff at the beginning of the calibration and vetting process described above.

- B. Conduct “as found” annual studies for years 2022, 2026, and 2030
  - 1. Evaluate operational performance, including the metrics as described above
  - 2. Quantify in MW the amount of effective capacity that should be added or removed to achieve an annual 0.1 LOLE target
  - 3. Compare with results of the “as found” studies based on the RESOLVE model’s 2017 IEPR-updated 42 MMT core policy case used in the calibration and vetting process
- C. Calculate monthly average portfolio ELCC values for wind and utility solar
  - 1. For each month, calibrate the portfolio under study to the range of 0.02 to 0.03 LOLE for each month. Report the quantity of generation added or removed in MW.
  - 2. Calculate the monthly average portfolio ELCC of wind and utility solar together
- D. Calculate the monthly reserve margin and verify satisfaction of the PRM system reliability requirement in each month of the study year (relying on the ELCC values in step C.)

(End of Attachment B)